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Performance testing (of one unit each of Obra and Anpara TPS) and coal inventory management (at Obra TPS)

Prepared for **Uttar Pradesh Electricity Regulatory Commission**
Lucknow

TERI Project Report No. 2002ER65

Acknowledgement

We are greatly obliged to UP Electricity Regulatory Commission for giving us an opportunity to work with two power stations of UP Rajya Vidyut Utpadan Nigam Ltd We are thankful for constant guidance and support from the Chairman and Secretary of the Commission during the period of the study.

We are thankful for full support and co-operation from the Chairman and Directors of the UPRVU Nigam without which it would not have been possible to conduct this study

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S K Chand

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1 Introduction

The UP Electricity Regulatory Commission entrusted TERI with a study with the following terms of references.

a. **Evaluation of performance of two boilers (one at Anpara and the other at Obra)**
b. **Developing tools for improving the existing coal inventory management system at Obra thermal power plant**

The first process involved undertaking performance test of one boiler each at Anapara TPS and Obra TPS with the coal available at the respective plants and based on the test results, to suggest avoidable energy losses in different areas and suitable measures to enhance the boiler efficiency by minimizing the avoidable losses TERI was also entrusted with the study of the existing instrumentation and control system associated with the boilers to explore improvements in the performance and monitoring practices of the existing systems.

On the inventory front, TERI was asked to study the present coal inventory management and assessment methodologies and suggest improvements for better inventory management and maintaining an efficient level of coal inventory at Obra thermal power station only

The study was of a very short duration and was supposed to be completed within 10 weeks

The performance testing of Obra and Anpara was conducted along with the study of existing coal handling arrangements and coal inventory management systems during first week of April this year The draft report was submitted within the time limit and comments were received both from the UPERC and UPRVUNL These comments were examined and corrections/modifications incorporated in this final report wherever found suitable Responses to all the comments were also sent to the Commission, a copy of which is annexed at the end of this report.

2 Performance testing of Anpara TPS

Do not guess when you can calculate Do not calculate when you can measure. –Archimedes

2.1 Introduction

Anpara Thermal Power Station (ATPS), Anpara is equipped with 3x210 MW and 2x500 MW units The plant has come up in two phases In first phase, 3x210 MW and in second phase 2x500 MW units were installed. The total capacity of the power plant is given in the table 2.1.

Table2.1 Installed Capacity at Anpara

	Unit	MW	Date of commissioning	Turbine manufacturer	Boiler manufacturer
Phase I "A"TPS	I/1	210	Mar-86	BHEL	BHEL
	I/2	210	Feb-87	BHEL	BHEL
	I/3	210	Mar-88	BHEL	BHEL
Phase II "B"TPS	II/4	500	Jul-93	Toshiba, Japan	BHI, Japan
	II/5	500	Jul-94	Toshiba Japan	BHI Japan
Total		1630			

ATPS is getting coal mainly from nearby coalmines, which are spread, in a radius of a maximum of 34 kilometres as shown in table 2 2

Table 2.2 Distance of mines from the TPS

Mine	Km
Dudhichua	34
Khadia	23
Bina	8
Kakri	5

2.2 Details of boiler

The power plant management selected Unit#3 for detailed performance analysis and efficiency testing. The boiler is BHEL make, pulverised coal fired and has the design capacity of 210 MW. It is radiant reheat, natural circulation, and single drum boiler The boiler is equipped with three super heating surfaces with the arrangement of feed water spray for de-superheating. Reheating surface is provided between super heaters with the facility of attemeperation. Heat recovery units like economiser and air heaters are provided in the flue gas path. Economiser is made of seamless steel tube whereas air heater is regenerative type

There are four tilting nozzle type pulverised coal fire burners located in each corner of furnace to produce tangential flame Four nos. of air atomised oil fired start-up and warm up burners are also provided in the boiler furnace The fuel preparation equipment are primarily bowl mills arranged for pressurised operation Each mill has separate raw coal feeder. Pulverised fuel from each mill is taken to each burner's wind box located in the four corners of the furnace at one level for firing. The boiler is also equipped with two nos. each of forced draught and induced draught fans The design data of the boiler is given in table 2 3.

Table 2.3 Details of Unit # 3

S No	Description (Design data)	Unit	100% MCR
1	Steam generation capacity	t/h	680
2	Steam pressure at superheater outlet header	kg/cm² (g)	155
3	Steam temperature at superheater outlet header	°C	540
4	Reheater outlet steam flow	t/h	597.5
5	Steam pressure at reheat inlet header	kg/cm² (g)	37 6
6	Steam pressure at reheat outlet header	kg/cm² (g)	36 1
7	Steam temperature at reheat inlet header	°C	342
8	Steam temperature at reheat outlet header	°C	540
9	Feed water temperature at economiser inlet	°C	242 7
10	Feed water temperature at economiser outlet	°C	284
11	Total combustion air flow	t/h	907
12	Primary air heater outlet temperature	°C	323
13	Secondary air heater outlet temperature	°C	316
14	Ambient air temperature	°C	38
15	Coal consumption	t/h	141 6
16	Flue gas temperatures		
	a SH platen inlet	°C	1155
	b RH front inlet	°C	1028
	c RH rear inlet	°C	922
	d Finish SH inlet	°C	757
	e LTSH inlet	°C	722
	f Economiser inlet	°C	468
	g Air heater inlet	°C	349
	h Air heater outlet	°C	129

2 1 *Fuel*

This boiler is mainly designed for pulverised coal firing There are 6 pulverisers and out of these 5 were in operation during the time of study. Coal of the size <20mm comes to pulverisers and gets ground between grinding roll and the revolving bowl in the pulverisers Recommended fineness for the milled coal is 70% through 200 mesh screen The transport of pulverised coal from the mill to the boiler furnace is done by hot primary air The unit#3 is designed for the coal having the properties mentioned in table 2 4.

Table 2.4 Design coal properties

Parameters	Value
Proximate analysis (% by weight)	
Moisture	11
Ash	33
Fixed carbon	28
Volatile matter	28
Ultimate analysis (% by weight)	
Carbon	40 40
Hydrogen	3 14
Sulphur	0 5
Oxygen	11 12
Nitrogen	0 84
Ash	33
Moisture	11
Higher heating value (GCV in kcal/kg)	3750

During the testing of Unit#3, coal samples were collected for carrying out proximate and ultimate analysis in a reputed laboratory The result of the tests from Shriram Institute for Industrial Research is tabulated in table 2 5 A copy of the test report is placed at Annexure 2 1

Table 2.5 Tested coal properties

Parameters	Value	Value
Proximate analysis (% by weight)	*(as fired basis)*	*(as fired basis)*
Moisture	7 06	7 06
Ash	38 16	38 16
Fixed carbon	31 7	31 7
Volatile matter	23 08	23 08
Ultimate analysis (% by weight)	*(on dry basis)*	*(on wet basis)*
Carbon	46 45	43 17
Hydrogen	4 12	3 83
Sulphur	0 32	0 30
Oxygen	7 04	6 54
Nitrogen	1 01	0 94
Ash	41 06	38 16
Moisture	--	7 06
Higher heating value (GCV in kcal/kg)	4380	4071

The power plant is using better coal than the coal for which the boiler of unit#3 is designed as is clearly indicated in table 2.5. Carbon content, ash and GCV are higher than the design coal values.

2 2 2 Feed water system

Condensed steam from the condensor comes to hot well at 55±5°C, which is the inlet water temperature for the first stage of LP heaters. From LP heaters, feed water goes to deaerator, HP heater, economiser and finally to the boiler drum. Steam from turbine is extracted at various stages to preheat the feed water in LP/HP heaters and deaerator The temperatures, as reported during the visit, after various stages are shown in the table 2.6

Table 2.6 Feed water temperaturs

Stages	Temperature (°C)
At hot well	55±5
After LP heaters	115±5
After deaerator	160±5
After HP heaters	235±5
After economiser	345±5*

*Showing higher value as the design value is 284°C

The make up water quantity varied from 8TPH to 16 TPH. It is taken from the DM water plant. The TDS and pH of make up water is < 2 ppm and 7 respectively

2 2 3 Blow down

The blowdown from the drum is continuous in unit#3 boiler The blowdown water conductivity and pH are reported to be in a range of 15-18 units (about 30-40 ppm of TDS) and 9.5 respectively. The silica content is in a range of 0.23-0.28 ppm The values of conductivity, pH and silica for feed water are in a range of 4-6 units (8-12 ppm of TDS), 9 and 0 02-0 04 ppm respectively. All the parameters mentioned above are being maintained in the prescribed limits.

2.3 Boiler efficiency test

The boiler efficiency can be computed either by direct method from the heat input and output or by the losses (indirect) method. The reliability and accuracy of the fuel flow and steam flow measurements are very critical for the direct method, which will be quite misleading some times. Hence, indirect method was chosen to compute the actual efficiency ASME method is used for efficiency calculation.

The heat losses from the boiler include

- Dry gas loss which is a function of excess air and the flue gas composition and the corresponding gas temperature at air heater outlet Correction has been applied to AH outlet flue gas temperatures considering air ingress in the system. This was established by taking flue gas measurements after the boiler and after air heater
- Heat loss due to presence of CO in the flue gas
- Losses due to combustion of hydrogen and moisture which depends on H_2 in fuel, moisture in fuel, combustion air, excess air quantity and exit gas temperature
- Unburnt losses
- Sensible heat loss in ash

2.3.1 Basic input data for computing boiler efficiency

The parameters measured/collected from the plant for the performance evaluation of the boilers by indirect method, are given below.

1. Oxygen percentage in flue gas
2. Carbon monoxide level in flue gas
3. Flue gas temperature
4. Drum pressure
5. Feed water temperature
6. Steam flow rate
7. Analysis of coal and ash
8. Ambient conditions (temperature and relative humidity)

The flue gas composition and temperature, ambient conditions and other relevant parameters for evaluating the efficiency of the boilers were measured using portable instruments at site Survey of the surface temperatures at different boiler sections was also conducted to ascertain the condition of insulation and identification of hot spots Main parameters used for the calculation are given in table 2 7

Table 2.7 Measured parameters used for efficiency calculations

Parameters	Values
Measurements & observation	
Oxygen content in flue gas* (%)	0.37
Excess air level* (%)	1.81
CO level (%)*	1%
Flue gas temperature** (°C)	218
Ambient conditions	
Dry bulb temperature (°C)	30
Wet bulb temperature (°C)	25.3

* after superheater

** corrected for air ingress at the out let of air heaters. Actual measured flue gas temperature was 122°C

2.3.2 *Observations and recommendations*

The boiler was operating at 190±5 MW and it was not possible to further load this boiler. Measurements were taken at this boiler load. The summary of the boiler performance, as evaluated by the indirect method, is given in table 2.8 and also compared with the design efficiency. Annexure 2.2 gives more details of the calculations.

Table 2.8 Performance of unit#3 boiler

Losses	Calculated	Design
Heat balance		
Dry flue gas loss (%)	10.28	4.53
- Loss due to sensible heat (%)	6.95	
- Loss due to CO (%)	*3.33*	
Loss due to hydrogen and moisture (%)	6.72	6.55
Loss due to moisture in air (%)	0.23	0.21
Unburnt loss (%)	4.64	2
- Due to unburnt in bottom ash (%)	*4.46*	
- Due to unburnt in fly ash (%)	*0.18*	
Loss due to sensible heat in ash (%)	1.11	-
- Due to sensible heat in bottom ash (%)	*1.0*	
- Due to sensible heat in fly ash (%)	*0.11*	
Structural and unaccounted loss (%)	1.71	1.71
Total heat losses (%)	24.68	15
Boiler efficiency (%)	75.32	85

Comparing the design and calculated data, it can be seen that the design heat losses are 15 % only where as the actual ones are 24.68%. The biggest difference is in the dry flue gas loss which is about 5.75%. Another sizeable difference is in the unburnt loss amounting to be 2.64%. Another difference is of the loss due to sensible heat in ash which is not considered while calculating the design efficiency. It is expected that the gap between design and actual efficiency can be bridged by implementing the recommendations given in the following section of the report.

The dry flue gas loss mainly depends on two factors namely a) excess air level and b) flue gas temperature at the exit. Total dry flue gas loss is calculated to be about 10.28% which is on higher side. This loss consists of two factors 1) loss due to sensible heat in flue gas and 2) loss due to CO in flue gas The former is higher because of high flue gas temperature whereas the latter is high because of high CO. This is due to low excess air

2.3.2.1 Excess air level

Excess air is one of the important parameter in determination of boiler's performance. Every fuel needs a specified quantity of stoichiometric air for its combustion. In actual practice, since, mixing of fuel with air is never perfect, a certain amount of excess air is always needed to complete the combustion and ensure the release of entire heat contained in the fuel. Too much of air results in excessive heat loss as the superfluous air does not take part in combustion but carries away heat to the atmosphere from the boiler furnace Besides, surplus air lowers the furnace temperature and thereby the heat transfers rate, and hence results in lower combustion efficiency

Likewise, if the excess air is too less than the optimum quantity, combustion would be incomplete resulting in the formation of gases like carbon monoxide etc, in the flue gas. The maximum permissible limit for CO is 0 1% Above this, loss due to CO formation is much higher than the benefit availed on account of lower excess air level.

As is clear from the table 2 7, the excess air level in the boiler is very low i e less than 2%. Due to this, high quantity of CO, above 1%, was observed in flue gas The loss due to CO is worked out to be 3 33% The recommended excess air level for such type of boilers is 25-30% and it is suggested to maintain such level to operate boiler with optimum efficiency It is expected that with 25-30% excess air level, CO quantity would be in the permissible limit and this will lead to an increase in efficiency

Unit#3 is not able to maintain this excess air level because of the problem in ID fan. It was observed that ID fans were operating at full load whereas the FD fans were at 80% of their rated capacity. Due to this, any attempt to increase airflow in furnace will lead to furnace pressurisation as ID is not capable to handle any additional quantity of flue gases This could be one of the reasons why unit#3 is not able to operate near to its design capacity of 210 MW. Moreover, operation of ID and FD is not interlocked and the furnace pressure is maintained at about −1 mmWC. Due to this furnace pressure occasionally goes in to positive side Since, ID fan is already running at its rated capacity it is not able to even cater to the small fluctuations. Such operational practices are not recommended at all and steps must be taken to operate furnace always at recommended negative pressure.

BHEL, Ranipet was contacted by TERI to ascertain the possibility of rectification of ID fan problem. They feel that new design of impeller can be offered which can be retrofitted in the existing fan housing to cater to the additional volume required to be handled by the fan. But prior to giving offer for the new design of impeller, BHEL would like to conduct performance measurement on these ID fans to assess the exact volume flow through the fans.

It is recommended that plant authorities may contact to BHEL and get this problem rectified as soon as possible in order to operate the boiler at improved efficiency and safely The improvement in efficiency by implementing this suggestion is shown in table 2.9 It may be seen that the gain in efficiency is 1 2%, which is substantial.

Table 2.9 Improvement in efficiency

Boiler	Current oxygen &CO level in flue gas (%)	Efficiency with current oxygen & CO level (%)	Efficiency with 4 2% oxygen& 0 1% CO level (%)
Unit#3	1 8(O_2) and >1(CO)	75 32	76 52

2.3.2.2 Flue gas temperature

Flue gas temperature is another major contributor to the dry flue gas loss and also has the impact on other losses The flue gas temperature after air heater is measured to be 122°C Lot of air infiltration was also observed between economiser and air heaters and within air heaters This is evident from the average oxygen percentage measured at three different locations namely before economiser, after economiser and air heaters which are tabulated below Actual flue gas temperature after air heaters is re-worked after compensating for cold air ingress and found to be about 218°C For boiler efficiency calculations this flue gas temperature is used.

Table2.10 Average O_2 content in flue gas

	Before economiser	After economiser	After air heaters
Average O_2% in flue gas (%)	0 37	1 5	11
Excess air level (%)	1 8	8	110

Ingress of cold air into the flue gas path reduces the flue gas temperature and thereby the useful heat transfer back to the boiler system. It also increases the ID fan duty as it sucks infiltrated cold air from the near by leakage points This reduces the actual capacity of ID fan available for providing adequate suction in the boiler furnace It is also evident from the current operating practices where FD fans are operating at about 80% its rated capacity and ID fans are almost fully loaded. Air infiltration could be one of the reasons for almost 100% loading of ID fans and because of which boiler is not able to go beyond 190 MW loading and operate at adequate excess air level

The heat transfer to the primary and secondary air in the air heater is also low due to the flue gas dilution The design primary and secondary air heater outlet temperatures are 323°C and 316°C respectively whereas actually, they are about 275°C It is therefore, recommended that immediate steps should be taken to stop cold air ingress, which may be from the joints in the duct, sealings in air heater, etc. This will lead to better heat transfer in air heaters, improved suction in the furnace, lower load of ID fans, etc. It is assumed that actual flue gas temperature will be about 140°C after the elimination of air leakage in the system The improvement in the efficiency due to this is mentioned in table 2 11

Table2.11 Improvement in efficiency

Boilers	Flue gas temperature (°C) Current	Recommended	Efficiency with current flue gas temperature (%)	Efficiency with recommended flue gas temperature (%)
Unit#3	218(122)*	140±5	75 32	78 76

* Corrected temperature Measured temperature is shown in the bracket

The savings by controlling excess air level and flue gas temperature are shown in the table 2.12. The savings are shown in terms of coal only Detailed calculation is given in the Annexure 2 3

Table 2.12 Coal and monetary savings

Boilers	*Current efficiency (%)*	*Improved efficiency (%)*	*Coal savings* (MT)*	*Monetary savings* (Rs Lakh)*
Unit#3	75 32	80 68	68995	620 9

- Per annum based on coal cost = Rs 900 per ton

2 3 3 Loss due to hydrogen and moisture in coal

This is the second biggest loss and depends upon the moisture and hydrogen content of the fuel. All these parameters are beyond the control of the boiler operator The controllable factor on which it depends is flue gas exit temperature By maintaining temperature to a prescribed limit this loss will also be reduced marginally, from existing 6 72% to 6 37%. The savings due to reduction in this loss is already been considered in table 2.12.

2 3 4 Loss due to unburnt in ash

This loss is calculated to be 4.64% Maximum contribution to this loss is due to unburnt in bottom ash which is 4 46%. Higher pulverised coal size could be one of the reason for this. The recommended coal size is >70% through 200 mesh as suggested by the supplier. Two of the operating mills (C & E) were not able to pulverise the coal within the prescribed limit and about 60% of pulverise coal could pass through the 200-mesh screen (refer to annexure 2.4). It is hoped that proper grinding of coal in all the pulverisers would bring down the unburnt levels in bottom ash and thereby the unburnt loss.

2.3 5 Sensible heat loss in ash

This heat loss is due sensible heat carried away in bottom ash and fly ash and depends on the bottom ash disposal and flue gas temperature. These losses are 1 0% and 0 11% respectively for bottom and fly ash. Reduction in flue gas temperature will reduce the loss due to sensible heat in fly ash to 0.06%. The savings due to reduction in this loss is already been considered in table 2 12

2.3 6 Loss due to moisture in air

This loss is because of moisture content in air, which depends on the relative humidity and the ambient temperature. The other controllable factors, on which this loss depends, are excess air level and flue gas temperature. Presently, this loss is calculated to be 0 23% and will be reduced to 0 17 after implementing the given recommendations The savings due to reduction in this loss is already been considered in table 2.12.

2 3 7 Radiation and unaccounted loss

The structural and unaccounted losses are considered to be 1.71% which is as prescribed by the supplier. However, exercise was carried out to identify the hot spots Few spots like inspection doors and windows need special attention for insulation as the temperature was measured to be in the range of 75 – 110 °C.

2.4 Unit heat rate

The overall heat rate for unit#3 is reported to be 2130 kcal/kwh as per the PG test report It was found, from the log sheets that the actual operating heat rate and corresponding specific fuel consumption are about 3200±50 and 0 7663 respectively.

2.5 Turbine-generator heat rate

Unit#3 is equipped with one BHEL make steam turbine of the capacity 210 MW The type of steam turbine is reaction, condensing, reheating, horizontal and regenerative. The governing system is electro-hydraulic type and backed up with hydro-mechanical type. It is designed for the steam conditions of 150 kg/cm^2 (g) pressure and 530°C. The design turbine heat rate is stated to be 2100 kcal per kWh at design conditions whereas the unit was operating at 2500±50 as reported. The design efficiency of the generator is 98.55% and it operates at 0.85 lagging power factor

2.6 Instrumentation

The level and conditions of the instruments were found to be satisfactory Some of the instruments were not operating or showing wrong readings, during the visit of TERI team. These are listed below

- furnace pressure controller
- indicator showing feed water temperature after economiser
- both the vacuum gauges were found to be showing different condenser pressures

It is suggested to get these instruments/control systems rectified or replaced to have a better control over boiler

2.7 Conclusions

It is expected that after implementing the suggestions made in the report, boiler efficiency is likely to improve by 5 36% to 80 68%. The comparison between the improved and design efficiency levels are made in table 2.13.

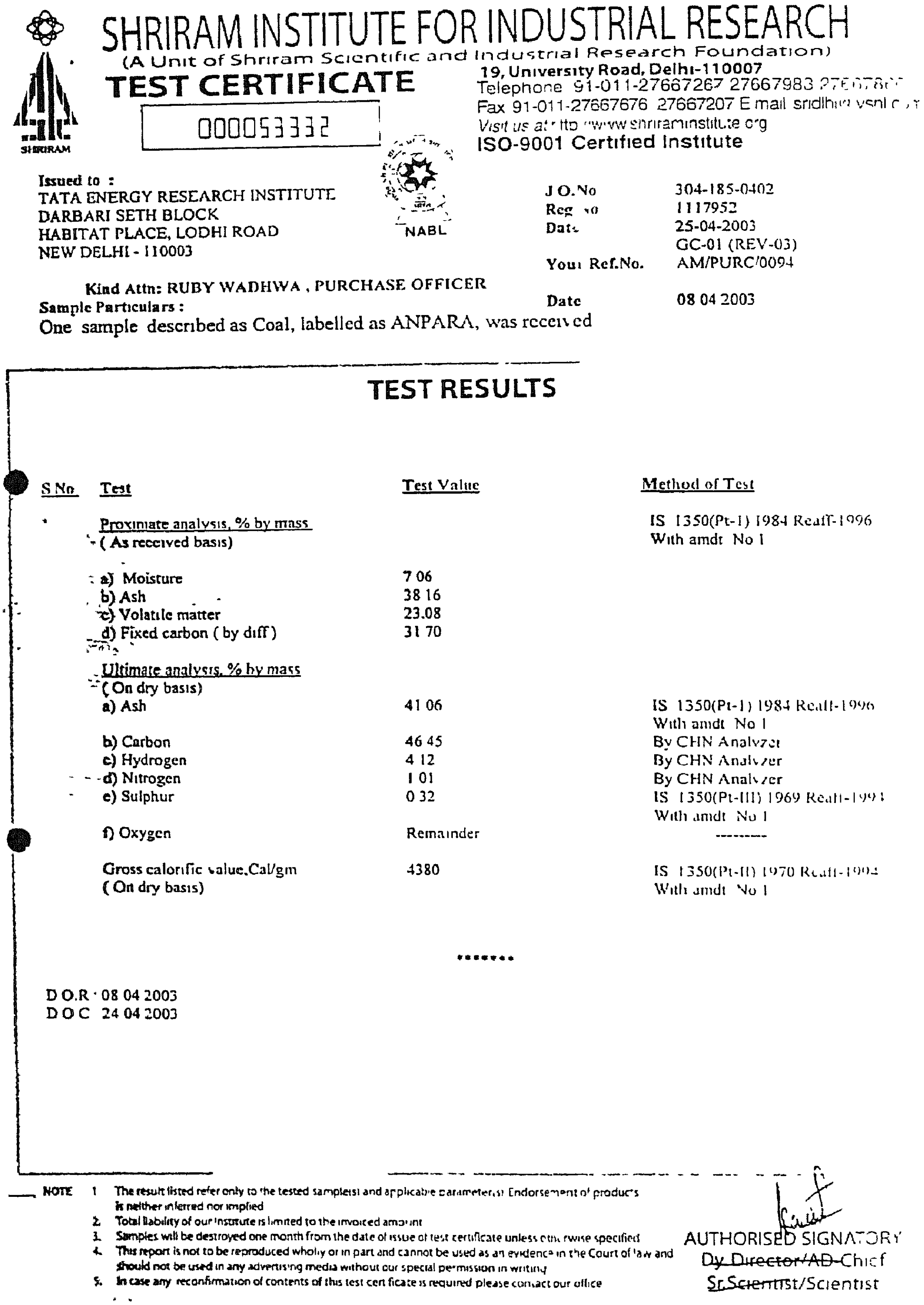
Table 2.13 Comparison between improved and design efficiencies forunit#3 boiler

Losses	*Improved*	Design
Heat balance		
Dry flue gas loss (%)	5 39	4 53
- Loss due to sensible heat (%)	*4.97*	
- Loss due to CO (%)	*0.42*	
Loss due to hydrogen and moisture (%)	6 37	6 55
Loss due to moisture in air (%)	0 17	0 21
Unburnt loss (%)	4 64	2
- Due to unburnt in bottom ash (%)	*4 46*	
- Due to unburnt in fly ash (%)	*0 18*	
Loss due to sensible heat in ash (%)	1 06	-
- Due to sensible heat in bottom ash (%)	*1.00*	
- Due to sensible heat in fly ash (%)	*0 06*	
Structural and unaccounted loss (%)	1 71	1 71
Total heat losses (%)	**19 32**	**15**
Boiler efficiency (%)	**80 68**	**85**

As is clear from the above table, the gap between improved and design efficiency is quite wide which could mainly be attributed to following reasons.

- operation at lower capacity (at 195±5 MW instead of design 210 MW)
- aging or wear and tear of boiler
- design efficiency does not consider "loss due to sensible heat in ash" and "loss due to presence of CO in flue gas" as losses
- unburnt loss in present condition is 4 64% which is higher by 2.64% than the designed value However, it is felt that maintaining the proper coal sizing from the mills (>70% through 200 mesh screen), this loss will come down significantly

Annexure2.1



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Date 25-04-2003
GC-01 (REV-03)
Your Ref.No. AM/PURC/0094
Date 08 04 2003

Kind Attn: RUBY WADHWA , PURCHASE OFFICER

Sample Particulars :

One sample described as Coal, labelled as ANPARA, was received

TEST RESULTS

S No	Test	Test Value	Method of Test
	Proximate analysis, % by mass (As received basis)		IS 1350(Pt-I) 1984 Reaff-1996 With amdt No 1
	a) Moisture	7 06	
	b) Ash	38 16	
	c) Volatile matter	23.08	
	d) Fixed carbon (by diff)	31 70	
	Ultimate analysis, % by mass (On dry basis)		
	a) Ash	41 06	IS 1350(Pt-I) 1984 Reaff-1996 With amdt No 1
	b) Carbon	46 45	By CHN Analyzer
	c) Hydrogen	4 12	By CHN Analyzer
	d) Nitrogen	1 01	By CHN Analyzer
	e) Sulphur	0 32	IS 1350(Pt-III) 1969 Reaff-1994 With amdt No 1
	f) Oxygen	Remainder	---------
	Gross calorific value,Cal/gm (On dry basis)	4380	IS 1350(Pt-II) 1970 Reaff-1994 With amdt No 1

•••••••

D O.R · 08 04 2003
D O C 24 04 2003

NOTE
1 The result listed refer only to the tested sample(s) and applicable parameter(s) Endorsement of products is neither inferred nor implied
2. Total liability of our Institute is limited to the invoiced amount
3. Samples will be destroyed one month from the date of issue of test certificate unless otherwise specified
4. This report is not to be reproduced wholly or in part and cannot be used as an evidence in the Court of law and should not be used in any advertising media without our special permission in writing
5. In case any reconfirmation of contents of this test certificate is required please contact our office

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~~Dy Director/AD~~-Chief
~~Sr.Scientist~~/Scientist

Annexure2.2

Boiler efficiency

Parameters	Unit#3
Oxygen in flue gas (%)	0.37
Carbon monoxide in flue gas (%)	1
Carbon dioxide in flue gas (%)	16 85
Excess air (%)	1 81
Flue gas temperature (°C)	218*(122)
Theoretical air requirement (kg/kg of fuel)	6 02
N2 in flue gas (%)	81 78
Dry flue gas quantity (kg/kg of fuel)	6 21
Nitrogen quantity in flue gas (kg/kg of fuel)	4 63
Inlet air quantity (kg/kg of fuel)	6 01
Heat released by burning 1 kg of carbon (kcal/kg)	8084
Mean specific heat of flue gas (KJ/kg C)	1.0236
Moisture calculation	
Air	
DBT (°C)	30
WBT (°C)	25 3
Humidity ratio (kg/kg of dry air)	0 0184
GCV of coal (as fired)	4071
Heat with pulverised coal (kcal/kg of coal)	25
Total heat available (kcal/kg of coal)	4096
Fuel	
Moisture in fuel (kg per kg of fuel)	0 0706
Hydrogen in fuel (kg per kg of fuel)	0 0383
Total moisture in flue gas (kg per kg of fuel)	0 523
Specific heat of moisture (Kcal/kg-°C)	0 4498
Losses %	
Dry flue gas loss	6 95
Heat loss due to CO in flue gas	3 33
Heat loss due to moisture in air	0 23
Heat loss due to moisture and hydrogen in the fuel	6 72
Heat loss due to unburnt in bottom ash	4 46
Heat loss due to unburnt in fly ash	0 18
Sensible heat loss in bottom ash	1 00
Sensible heat loss in fly ash	0 11
Radiation and unaccounted heat loss	1 71
Total Losses	24 68
Thermal Efficiency	75 32

* corrected

Annexure 2.3

Savings due to operating in prescribed limit

Existing flue gas conditions

Oxygen (%) = 0.37
Carbon monoxide (%) = 1
Flue gas temperature (°C)# = 218 (122)
Thermal Efficiency (%) = 75 32

Improved flue gas conditions

Oxygen (%) = 4.2
Carbon monoxide (%) = 0.1
Flue gas temperature (°C) = 140
Thermal Efficiency (%) = 80 68

Fuel consumption (MT/month) = 86598
Fuel savings (MT/month) = 5750
Fuel saving per annum (MT) = 68995
Monetary savings (Rs Lakh) = 620 9
(Delivered cost of coal = Rs 900 per MT from Khadia)

#corrected temperature Measured temperatures are shown in the bracket

Annexure-2.4

Coal fineness analysis (3rd April 2003)

Bowl Mill Number	Percent retained on sieve of the mesh size			Percent passed through the sieve of the mesh size		
	52	100	200	52	100	200
3A	2 38	8 81	21 95	97 62	91 19	78 05
3B	2 55	9 15	23 62	97 45	90.85	76 38
3C	3 24	20 09	39 93	96 76	79 91	60 07
3D	0 82	8.89	25 67	99 18	91 11	74 33
3E	0 44	10 61	38 75	99 56	89 39	61 25

3

Performance testing of Obra TPS

3.1 Introduction

Obra Thermal Power Station (OTPS), Obra is equipped with 5 x 50 MW, 3 x 100MW and 5 x 200 MW units The total capacity of the power plant is 1550 MW OTPS is getting coal from nearby coalmines, which are spread in a radius of 60 kilometres (Bina @59 km and Jhingurda @55 km) and also from Karanpura Coalfields in Bihar at a distance of about 300 km Though it is situated in the heart of a major coalfield, it is not treated as a pithead plant. The details of units are given below in table 3.1.

Table3.1 Installed Capacity at Obra

	Unit	MW	Date of commissioning	Turbine manufacturer	Boiler manufacturer
Phase I	I/1	50	Aug-67	LMW, USSR	KKBW, USSR
	I/2	50	Mar-68	LMW, USSR	KKBW, USSR
	I/3	50	Oct-68	LMW, USSR	KKBW, USSR
	I/4	50	Jul-69	LMW, USSR	KKBW, USSR
	I/5	50	Jul-71	LMW, USSR	KKBW, USSR
	I/6	100	Jul-73	BHEL	BHEL
	I/7	100	Dec-74	BHEL	BHEL
	I/8	100	Sep-75	BHEL	BHEL
Phase II	II/9	200	Jan-80	BHEL	BHEL
	II/10	200	Jan-79	BHEL	BHEL
	II/11	200	Dec-77	BHEL	BHEL
	II/12	200	Mar-81	BHEL	BHEL
	II/13	200	Mar-82	BHEL	BHEL
Total		1550			

3.2 Details of boiler

The power plant management selected Unit#12 for detailed performance analysis and efficiency testing The boiler is BHEL make, pulverised coal fired and has the design capacity of 200 MW. It is radiant reheat, natural circulation, and single drum boiler The boiler is equipped with three super heating surfaces with the arrangement of feed water spray for de-superheating. Heat recovery units like economiser and air heaters are provided in the flue gas path.

Economiser is made of seamless steel tube whereas air heater is regenerative type.

There are four tilting nozzle type pulverised coal fire burners located in each corner of furnace to produce tangential flame. Four nos. of air atomised oil-fired start-up and warm up burners are also provided in the boiler furnace The fuel preparation equipment has primarily six bowl mills arranged for pressurised operation Each mill has separate raw coal feeder. Pulverised fuel from each mill is taken to each burner's wind box located in the four corners of the furnace for firing. The boiler is also equipped with two each of forced draught and induced draught fans. The salient details of the unit are given below in table 3.2.

Table 3.2 Details of unit#12

S No	Description (Design data)	Unit	*100% MCR*
1	Steam generation capacity	t/h	680
2	Steam pressure at superheater outlet header	kg/cm² (g)	136
3	Steam temperature at superheater outlet header	°C	540
4	Reheater outlet steam flow	t/h	560 7
5	Steam pressure at reheat inlet header	kg/cm² (g)	26
6	Steam pressure at reheat outlet header	kg/cm² (g)	24.24
7.	Steam temperature at reheat inlet header	°C	323
8	Steam temperature at reheat outlet header	°C	540
9	Feed water temperature at economiser inlet	°C	242
10	Feed water temperature at economiser outlet	°C	281
11	Ambient air temperature	°C	38
12	Coal consumption	t/h	111
13	Flue gas temperatures		
	a Leaving furnace	°C	1120
	b Reheater inlet	°C	1007
	c Reheater outlet	°C	788
	d LTSH inlet	°C	709
	e Economiser inlet	°C	476
	f Air heater inlet	°C	362
	g Air heater outlet	°C	141

3.2.1 *Fuel*

This boiler is mainly designed for pulverised coal firing There are 6 pulverisers in all. Coal of the size <20mm comes to it and gets ground between grinding roll and the revolving bowl in the pulverisers Recommended fineness for this milled coal is 70% through 200-mesh screen The transport of pulverised coal from the mill to the boiler furnace is done by hot primary air. The unit#12 is designed for the coal having the properties mentioned in the table 3 3.

Table 3.3 Design coal properties

Parameters	Value
Proximate analysis (% by weight)	
Moisture	10
Ash	28
Fixed carbon	36.5
Volatile matter	25.5
Ultimate analysis (% by weight)	
Carbon	36.5
Hydrogen	3.4
Grindability (HGI)	50
Higher heating value (GCV in kcal/kg)	4750

During the study of Unit#12, coal samples as fed to the boiler were collected for carrying out proximate and ultimate analysis in a reputed laboratory, the result of which is tabulated in table 3.4 A copy of test report is placed at annexure 3.1.

Table 3.4 Tested coal properties

Parameters	Value	Value
Proximate analysis (% by weight)	*(as fired basis)*	*(as fired basis)*
Moisture	9.24	9.24
Ash	27.32	27.32
Fixed carbon	38.06	38.06
Volatile matter	25.38	25.38
Ultimate analysis (% by weight)	*(on dry basis)*	*(on wet basis)*
Carbon	55.84	50.68
Hydrogen	4.76	4.32
Sulphur	0.28	0.25
Oxygen	7.93	7.20
Nitrogen	1.09	0.99
Ash	30.10	27.32
Moisture	--	9.24
Higher heating value (GCV in kcal/kg)	5360	4865

The power plant is using better coal than the coal for which the boiler of unit#12 is designed as clearly indicated in table 3.4. Carbon content and GCV are high whereas the ash content is almost same as the design coal

3.2.2 *Feed water system and blowdown*

Condensed steam from the condensor comes to hot well, which is the inlet water for the first stage of LP heaters From LP heaters, feed water goes to deaerator, HP heater, economiser and finally to the boiler drum. Steam from turbine is extracted at various stages to preheat the feed water in LP/HP heaters and deaerator. The make up water is taken from the DM water plant The blowdown from the drum is continuous in unit #12 boilers. Sometimes, intermittent blowdown is also carried out depending upon the silica content in the boiler water.

3.3 Boiler efficiency test

The boiler efficiency can be computed either by direct method from the heat input and output or by the losses (indirect) method. The reliability and accuracy of the fuel oil flow and steam flow measurements are very critical for the direct method, which can be quite misleading some times. Hence, indirect method is chosen to compute the actual efficiency. ASME method is used for efficiency calculation.

The heat losses from the boiler include

- Dry gas loss, which is a function of excess air and the flue gas composition and the corresponding gas temperature at air heater outlet. Correction has been applied to AH outlet flue gas temperatures considering air ingress in the system. This was established by taking flue gas measurements after the boiler and after air heater 3
- Heat loss due to presence of CO in the flue gas
- Losses due to combustion of hydrogen and moisture, which depends on H_2 in fuel, moisture in fuel, combustion air, excess air quantity and exit gas temperature
- Unburnt losses
- Sensible heat loss in ash

3.3.1 Basic input data for computing boiler efficiency

The parameters measured/collected from the plant for the performance evaluation of the boilers by indirect method, are given below

(1) Oxygen percentage in flue gas
(2) Carbon monoxide level in flue gas
(3) Flue gas temperature
(4) Drum pressure
(5) Feed water temperature
(6) Steam flow rate
(7) Analysis of coal and ash
(8) Ambient conditions (temperature and relative humidity)

The flue gas composition & temperature, ambient conditions and other relevant parameters for evaluating the efficiency of the boilers were measured using portable instruments at site. Survey of the surface temperatures at different boiler sections was also conducted for ascertaining the condition of insulation and identification of hot spots. Main parameters used for the calculation are given in table 3.5.

Table3.5 Measured parameters used for efficiency calculations

Parameters	Values
Measurements and observation	
Oxygen content in flue gas* (%)	5 4
Excess air level*(%)	35%
CO level (%)*	0 1%
Flue gas temperature** (°C)	208
Ambient conditions	
Dry bulb temperature (°C)	30
Wet bulb temperature (°C)	27

* after superheater

** corrected for air ingress at the out let of air heaters Measured flue gas temperature was 150°C

3 2 *Observations and recommendations*

The boiler was operating at 180±5 MW and it was not possible to further load this boiler. Measurements were taken at this boiler load. The summary of the boiler performance, as evaluated by the indirect method, is given in table 3.6 and also compared with the design efficiency. Annexure 3.2 gives more details of the calculations

Table 3 6 Performance of unit#12 boiler

Losses	Calculated	Design
Heat balance		
Dry flue gas loss (%)	8 84	4 53
- loss due to sensible heat (%)	*8 40*	
- Loss due to CO (%)	*0 44*	
Loss due to hydrogen and moisture in fuel and moisture in air (%)	6 73	5 62
Unburnt loss (%)	2 52	2 00
- Due to unburnt in bottom ash (%)	*2 41*	
- Due to unburnt in fly ash (%)	*0.11*	
Loss due to sensible heat in ash (%)	0 65	
- Due to sensible heat in bottom ash (%)	*0 59*	
- Due to sensible heat in fly ash (%)	*0 06*	
Structural and unaccounted loss (%)	1.50	1 50
Total heat losses (%)	20 23	13 85
Boiler efficiency (%)	79 77	86 15

Comparing the design and calculated data, it can be seen that the design heat losses are 13 85 % only whereas the actual ones are 20 23% The biggest difference is in the dry flue gas loss, which is 8 84% as compared to the design value of 4 53% The dry flue gas loss mainly depends on two factors namely a) excess air level and b) flue gas temperature at the exit. This loss consists of two factors 1) loss due to sensible heat in flue gas and 2) loss due to CO in flue gas In the boiler under study, the dry flue gas loss is higher mainly because of high flue gas temperature, whereas CO level in flue gas is in permissible limit Another difference is of the loss due to sensible heat in bottom and fly ash, which has not been considered while calculating the design efficiency It is expected that the gap between design and actual efficiency can be bridged by implementing the recommendations given in the following part of the report

3.3.2.1 Excess air level

Excess air is one of the important parameter in determination of boiler's performance. Every fuel needs a specified quantity of stoichiometric air for its combustion. In actual practice, since, mixing of fuel with air is never perfect, a certain amount of excess air is always needed to complete the combustion and ensure the release of entire heat contained in the fuel. Too much of air results in excessive heat loss as the superfluous air does not take part in combustion but carries away heat to the atmosphere from the boiler furnace. Besides, surplus air lowers the furnace temperature and thereby the heat transfers rate, and hence results in lower combustion efficiency

Likewise, if the excess air is too less than the optimum quantity, combustion would be incomplete resulting in the formation of gases like carbon monoxide etc, in the flue gas The maximum permissible limit for CO is 0.1% Above this, loss due to CO formation is much higher than the benefit availed on account of lower excess air level. In the present case, the loss due to CO is 0 44%

As is clear from the table3 5, the excess air level in the tested boiler is 35%, whereas if the oxygen content in flue gases is reduced to 4.2%, the excess air level will be reduced to 25%. Table 3 7 shows the increase in efficiency if the oxygen level is maintained at 4 2% instead of 5 4 %

Table 3.7 Improvement in efficiency

Boiler	Current oxygen &CO level in flue gas (%)	Efficiency with current oxygen and CO level (%)	Efficiency with 4 2% oxygen and 0 1% CO level (%)
Unit#12	5 4(O_2) and 0 1(CO)	79 77	80 37

3.3.2.2 Flue gas temperature

Flue gas temperature is another major contributor to the dry flue gas loss and also has the impact on other losses. The flue gas temperature after air heater is measured to be 150 °C Lot of air infiltration was observed between economiser and air heaters. Actual flue gas temperature after air heaters is re-worked after compensating for cold air ingress and found to be about 208°C. For boiler calculations this flue gas temperature is used.

Ingress of cold air into the flue gas path reduces the flue gas temperature and thereby the useful heat transfer back to the boiler system. It also increases the ID fan duty as it sucks infiltrated cold air from the nearby leakage points This reduces the actual capacity of ID fan available for providing adequate suction in the boiler furnace. It is, therefore, recommended that immediate steps should be taken to stop cold air ingress which may be from the joints, sealings in the air heater, etc This will lead to better heat transfer in air heaters, improved suction in the furnace, lower load of ID fans, etc. It is assumed that actual flue gas temperature will be about 140°C after the elimination of air leakage in the system The improvement in the efficiency due to this is mentioned in the table 3 8

Table 3.8 Improvement in efficiency

Boilers	Flue gas temperature (°C)		Efficiency with current flue gas temperature (%)	Efficiency with recommended flue gas temperature of (%)
	Current	Recommended		
Unit#12	208*	140±5	79 77	83 53

* Corrected temperature Measured temperature was 150 °C

The savings by controlling excess air level and flue gas temperature are shown in the table 3 9. The savings are shown in terms of coal only Detailed calculation is given in the Annexure 3 3.

Table 3.9 Coal and monetary savings

Boilers	Current efficiency (%)	Improved efficiency (%)	Coal savings* (MT)	Monetary savings* (Rs Lakh)
Unit#12	79 77	83 92	38388	441 4

* Per annum based on coal cost = Rs. 1150 per ton

3.3.3 Loss due to hydrogen and moisture in coal and moisture in air

This is the second biggest loss and depends upon the moisture and hydrogen content of the fuel and moisture in air All these parameters are beyond the control of the boiler operator. The controllable factors on which it depends is flue gas exit temperature. By maintaining temperature to a prescribed limit this loss will also be reduced from existing 6.73% to 6 31%. The savings due to reduction in this loss is already been considered in table 3 9.

3.3.4 Loss due to unburnt in ash

This loss is calculated to be 2.52%, which is quite high Higher pulverised coal size could be one of the reason for this The recommended coal size is >70% through 200 mesh as suggested by the supplier. All of the operating mills were not able to pulverise the coal within the prescribed limit (refer annexure-3 4 also). It is hoped that proper coal sizing would bring down the unburnt levels in bottom ash and thereby the unburnt loss.

3.3.5 Sensible heat loss in ash

This heat loss is due to sensible heat carried away in bottom ash and flyash depends on the bottom ash disposal and flue gas temperature. These losses are 0.59% and 0.06% respectively for bottom and fly ash By reducing the flue gas temperature, this loss will also reduce to 0 04%. The savings due to reduction in this loss is already been considered in table 3 9

3.3.6 Radiation and unaccounted loss

The structural and unaccounted losses are considered to be 1 5% which is same as design value However, exercise is carried out to identify the hot spots Few spots like inspection doors and windows need special attention as the temperature is too high there.

3.4 Turbine-generator

Unit#12 is equipped with one BHEL make steam turbine of the capacity 200 MW The type of steam turbine is condensing tandem compound, three cylinders (H P , I P , and L.P), horizontal, disc and diaphragm type with nozzle governing and regenerative feed water heating The L.P turbine is double flow, which incorporates a multi exhaust in each flow. The governing system is hydro-mechanical type It is designed for the steam conditions of 130 kg/cm^2(g) pressure and 535°C. As informed by plant authorities, the design heat rate for turbine generator set has been taken as 2012 kcal/kwh.

3.5 Conclusions

It is expected that after implementing the suggestions made in the report, boiler efficiency is likely to improve by 4.15% to 83 92%. The comparison between the improved and design efficiency levels are made in table 3.10.

Table 3.10 Comparison between improved and design efficiencies for unit#12 boiler

	Improved efficiency	Design efficiency
Heat balance		
Dry flue gas loss (%)	5 14	4 53
- Loss due to sensible heat	*4 73*	
- Loss due to CO (%)	*0 41*	
Loss due to hydrogen and moisture in fuel and moisture in air	6 31	5 62
Unburnt loss (%)	2 52	2 00
- Due to unburnt in bottom ash (%)	*2 41*	
- Due to unburnt in fly ash (%)	*0 11*	
Loss due to sensible heat in ash (%)	0 63	-
- due to sensible heat in bottom ash (%)	*0 59*	
- Due to sensible heat in fly ash (%)	*0 04*	
Structural and unaccounted loss (%)	1 50	1 50
Total heat losses (%)	**16 08**	**13 85**
Boiler efficiency (%)	**83 92**	**86 15**

As is clear from the table 3 10, the gap between improved and design efficiency is quite wide which could mainly be attributed to following reasons.

- Operation at lower capacity (at 180±5 MW instead of design 200 MW)
- Aging or wear and tear of boiler
- Design efficiency does not consider "loss due to sensible heat in ash" and "loss due to presence of CO in flue gas" as losses

Annexure 3.1

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J O.No 304-185-0401
Reg No. 1117952
Date 25-04-2003
GC-01 (REV-03)
Your Ref.No. AM/PURC/0094
Date 08 04 2003

Kind Attn RUBY WADHWA , PURCHASE OFFICER

Sample Particulars
One sample described as Coal, labelled as OBRA, was received.

TEST RESULTS

S No	Test	Test Value	Method of Test
1	Proximate analysis % by mass (As received basis)		IS. 1350(Pt-1) 1984,Reaff-1996 With amdt No 1
	a) Moisture	9 24	
	b) Ash	27 32	
	c) Volatile matter	25 38	
	d) Fixed carbon (by diff)	38 06	
2	Ultimate analysis, % by mass (On dry basis)		
	a) Ash	30 10	IS 1350(Pt-1) 1984,Reaff-1996 With amdt. No 1
	b) Carbon	55 84	By CHN Analyzer
	c) Hydrogen	4 76	By CHN Analyzer
	d) Nitrogen	1 09	By CHN Analyzer
	e) Sulphur	0 28	IS 1350(Pt-III) 1969,Reaff-1994 With amdt. No 1
	f) Oxygen	Remainder	—
3	Gross calorific value,Cal/gm (On dry basis)	5360	IS 1350(Pt-II) 1970,Reaff-1994 With amdt. No 1

****

D O R 08 04 2003
D O C 24 04 2003

NOTE
1. The result listed refer only to the tested sample(s) and applicable parameter(s) Endorsement of products is neither inferred nor implied
2. Total liability of our Institute is limited to the invoiced amount
3. Samples will be destroyed one month from the date of issue of test certificate unless otherwise specified.
4. This report is not to be reproduced wholly or in part and cannot be used as an evidence in the Court of law and should not be used in any advertising media without our special permission in writing
5. In case any reconfirmation of contents of this test certificate is required, please contact our office

AUTHORISED SIGNATORY
Dy. Director/AD-Chief
~~Sr.Scientist/~~Scientist

Annexure3.2

Boiler efficiency

Parameters	Unit#12
Oxygen in flue gas (%)	5.4
Carbon monoxide in flue gas (%)	0.1
Carbon dioxide in flue gas (%)	13.24
Excess air (%)	35
Flue gas temperature (°C)	208
Theoretical air requirement (kg/kg of fuel)	7.01
N2 in flue gas (%)	81.26
Dry flue gas quantity (kg/kg of fuel)	9.62
Nitrogen quantity in flue gas (kg/kg of fuel)	7.21
Inlet air quantity (kg/kg of fuel)	9.38
Heat released by burning 1 kg of carbon (kcal/kg)	8084
Mean specific heat of flue gas (KJ/kg C)	1.0236
Moisture calculation	
Air	
DBT (°C)	30
WBT (°C)	27
Humidity ratio (kg/kg of dry air)	0.0184
Moisture content of air (kg/kg of air)	0.0184
GCV of coal(as fired)	4865
Heat with pulverised coal (kcal/kg of coal)	25
Total heat available (kcal/kg of coal)	4890
Fuel	
Moisture in fuel (kg per kg of fuel)	0.0924
Hydrogen in fuel (kg per kg of fuel)	0.0432
Total moisture in flue gas (kg per kg of fuel)	0.651
Specific heat of moisture (Kcal/kg-°C)	0.4498
Losses %	
Dry flue gas loss	8.40
Heat loss due to CO in flue gas	0.44
Heat loss due to moisture in air	0.28
Heat loss due to moisture and hydrogen in the fuel	6.45
Heat loss due to unburnt in bottom ash	2.41
Heat loss due to unburnt in fly ash	0.11
Sensible heat loss in bottom ash	0.59
Sensible heat loss in fly ash	0.06
Radiation and unaccounted heat loss	1.5
Total Losses	20.23
Thermal Efficiency	79.77

Annexure 3.3

Savings due to operating in prescribed limit

Existing flue gas conditions

Oxygen (%) = 5.4
Carbon monoxide (%) = 0.1
Flue gas temperature (°C)# = 208
Thermal Efficiency (%) = 79.77

Improved flue gas conditions

Oxygen (%) = 4.2
Carbon monoxide (%) = 0.1
Flue gas temperature (°C) = 140
Thermal efficiency (%) = 83.92

Fuel consumption (MT/month) = 64709
Fuel savings (MT/month) = 3274
Fuel saving per annum (MT) = 38388
Monetary savings (Rs Lakh) = 441 4
(Delivered cost of coal = Rs 1150 per MT)

#corrected temperature. Measured temperature was 150 °C

Annexure3.4

Coal fineness analysis

As on 1st April 2003

Bowl Mill Number	Percent retained in sieve of the mesh size			Percent passed through the sieve of the mesh size		
	50	100	200	50	100	200
12A	6 4	18.7	32 2	93 6	81 3	67 8
12B	3 6	13.5	25 8	96 4	86 5	74.2
12C	11 7	19 6	31 5	88 3	80 4	68 5
12D	12 6	28 7	40 1	87 4	71.3	59 9
12E	C	L	O	S	E	D
12F	22.1	34 4	44 2	77 9	65.6	55 8

As on 28th March 2003

Bowl Mill Number	Percent retained in sieve of the mesh size			Percent passed through the sieve of the mesh size		
	50	100	200	50	100	200
12A	4 9	11 8	34 4	95 1	88 2	65 6
12B	7 8	14 4	36 8	92 2	85 6	63 2
12C	15 7	24 4	32 3	84 3	75.6	67 7
12D	17 8	32 2	42 8	82.2	67 8	57.2
12E	9 7	17 8	39 2	90 3	82 2	60 8
12F	C	L	O	S	E	D

4 Inventory management and control

Something which is not measured can not be controlled

TERI was asked to undertake the study of the present coal inventory management and assessment methodologies and suggest improvements for better inventory management and maintaining an efficient level of coal inventory at Obra thermal power station

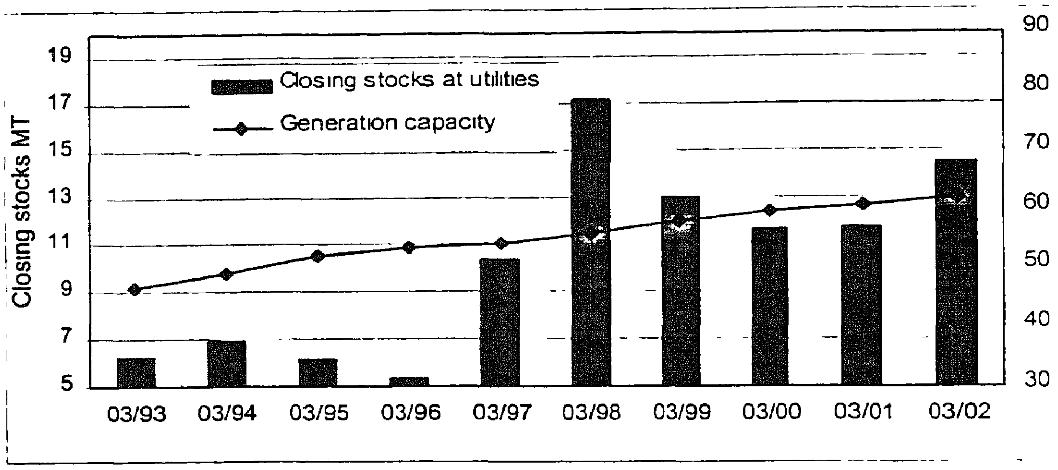
This essentially entailed the study of·

- Existing coal handling circuit
- Linkages and existing sources of supply of coal
- Coal consumption pattern
- Existing arrangements of stocks in the coal yard
- Studying the present reporting system at CHP level and suggest improvements in the system
- Developing mechanisms for accurate assessment and reporting of ground stock
- Developing tools for accurate recording of daily coal consumption
- Implementation of efficient stacking of coal
- Developing tools for ensuring efficient level of stock throughout the year
- Suggesting scientific method for efficient management of coal inventory

4.1 Sudden increase in stocks with utilities

The phenomena of extra large inventory holding started in the year 1996-97 when the total coal stocks for all coal fired power stations rose from less than 3 million tonne (MT) in January 1996 and a little over 5 MT in March 1996 to more than 10 MT in April 1997. Next year-end, in April 1998, it went up to more than 17 MT without corresponding increase in the generating capacity. Since then, the total closing stocks of coal at the utilities has been hovering around 14 MT As a rough estimate, more than 2,000 crores of working capital is currently locked up permanently in the coal inventory of all power utilities

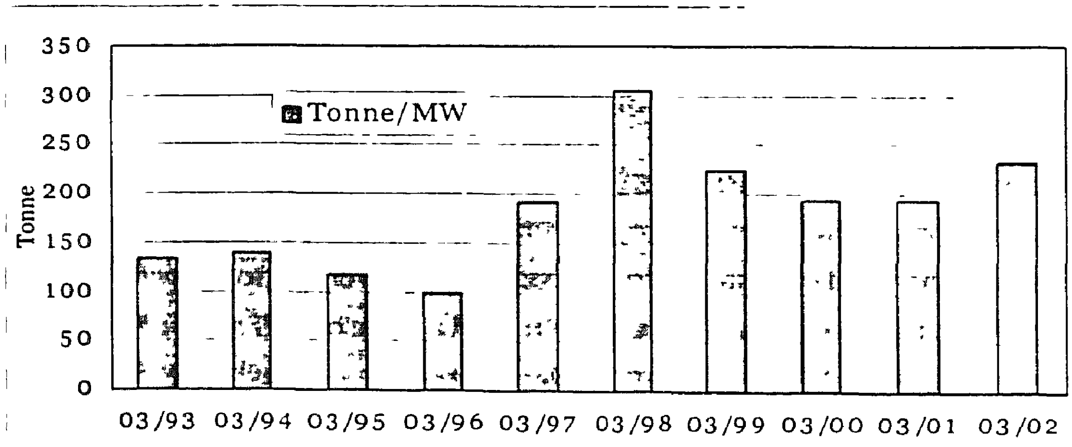
Chart 4.1 Generation capacity and closing stocks coal-fired utilities



Source CEA

In the pre 1997 period, the closing stocks at all coal fed power utilities were reported to be between 100 and 150 tonne/ MW. In 1998, it more than doubled to over 300 tonne per MW as result of sudden push by the coal industry. Presently it is hovering between 200 to 250 tonne/MW

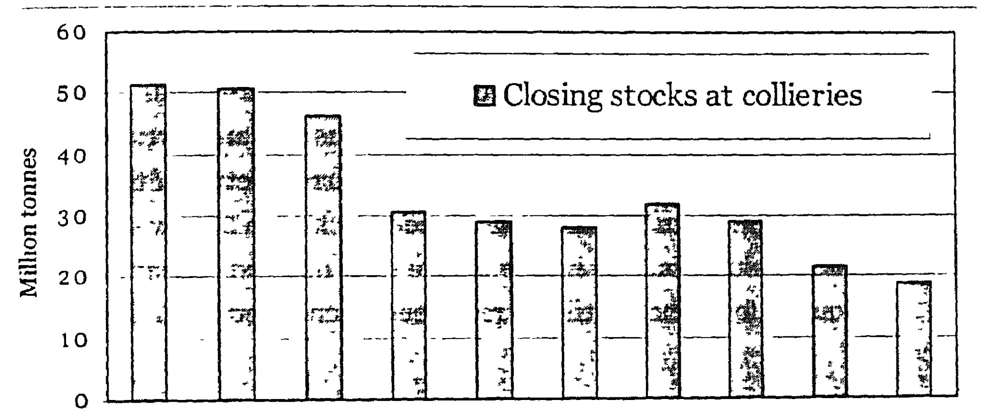
Chart 4.2 Closing stocks at coal-fired utilities tonne per MW



Source CEA

This sudden spurt in the stocks at power stations can be related to the sudden lowering of annual stock figure at the collieries during the same period. The closing stocks of all the collieries was about 20 MT in early eighties but the coal stocks started mounting and crossed the 30 million mark in 1987-88 due over production and low supplies coupled with bad planning Thereafter, it was at an all time high of more than 51 MT in 1992-93, the closing stocks of all collieries rising to 35% of the coal supplied to the utilities during the year. The closing stocks fell down to less than 30 MT in March 1996 and are back to around 18 MT in March 2002. This is only 8% of the total supplies to all utilities during the year

Chart 4.3 Closing stocks at collieries



Source Annual reports Ministry of Coal

Several power boards and power utility operators constantly represented against the uncertainties in coal supplies and increased costs of inventory but nothing much has happened.

4.2 Existing stocking norm

The Central Electricity Authority[1] (CEA), under Ministry of Power, monitors the stock position of all coal fed power stations everyday. Until recently, these power stations were required to carry coal stocks equivalent to either of 15 or 30 day's consumption, depending on whether they were pithead[2] or rail-fed utilities. The distance from the coal source, logistics of transportation or capacity to stock were not considered when this essentially adhoc norm was formulated

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[1] This is carried out by the Operation Monitoring (Fuel Management) Division, CEA, Ministry of Power, Government of India

[2] There is no standard definition of a 'pithead' but generally the plants with their own transport arrangements are treated as such

Several power boards and power utility operators constantly contested these norms and finally, a group was constituted by the Cabinet Secretariat under the chairmanship of the Secretary, Planning Commission in 2000[3] to review the stocking norms at coal fired power stations The Group submitted its report in August 2000 suggesting norms based on distance of the utility from the coal source and the mode of transport; all rail or rail-cum-sea. Only three broad slabs: less than 500 km, between 500 and 1200 km and more than 1200 km from the coal source were considered The report did not indicate if any kind of modelling was used to arrive at the slabs. The new norms were obviously based on an adhoc assessment much like the earlier one

The Group suggested that only utilities, located more than 1200km from the supply source, or fed by inter-modal systems of transport; need maintain a flat stock equivalent to 30 day's consumption, irrespective of their capacities. Those situated 500km to 1200km away needed to keep a 25 day's stock while utilities within 500km from the source of coal were advised to maintain 20 day's stock The norm for pithead utilities remained unchanged at 15 days.

Ministry of Power, CEA, NTPC and Council of Power Utilities (CPU) supported such a downward revision of the stocking norm The Ministry of Railways (MOR) and Ministry of Coal (MOC) were not in favour but for different reasons While MOR cited operational practices as the reason, MOC was of the opinion that such an action would give the impression that coal would somehow reach the station It gave examples of IPPs and practice in UK where stock levels are generally higher Ministry of Finance (MOF) took the pragmatic view that agreements should be in place with MOR and MOC for timely supply of coal so that the inventory could be optimised It also suggested the need for improvement in the process of coal movement. Planning Commission was concerned with the energy security and suggested that power sector should make efforts to reduce the specific coal consumption to reduce the stock levels It suggested that coal sector should try to improve the quality of coal supplies

Obviously, a very large coal stock at the power station would insulate the IR as well as the CIL from criticism but will mean a large amount of utility's working capital getting tied up in the coal resulting in a higher fuel cost.

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[3] Report of the Group to look into coal stock requirements of various thermal power stations, GOI, Planning Commission, Power & Energy Division, August 2000

Both the IR and the CIL do monitor the stocks at all coal fed power utilities in addition to the CEA. In cases of crisis, IR are known to have diverted coal meant for some other utility to the one in crisis even if it meant an irrational or costlier movement and consequent loss to them. Similarly, CIL has in past offered coal on priority from other sources even without pre-payment to tide over a critical situation at the utility. Their reluctance to agree to lower stocking norm, based on factors influencing its level, is essentially aimed only at reducing or eliminating the occurrence of such a crisis.

Clearly, the recommendation of CEA is not based on any scientific method There is a need for a scientific study to develop a model for optimisation of coal inventory, taking into consideration all the factors that can affect the supplies and stocking of coal in the power stations.

4.3 Ideal inventory management

In an ideal situation, the quantity of any raw material to be supplied is contracted with the supplier, fixing the frequency of supplies taking into consideration the seasonality of commodity use. The transporter guaranties its transportation on the desired frequency matching the use pattern. In such a situation, the consumer can easily optimize its inventory depending on the past performance of the transporter, material supplier and his own known or projected demand of the commodity Such a system ensures that there are no stock-outs and stocks held at any point of time is not more than the minimum required to guard against the probable failures of various systems of production and transport. Many developed countries, especially Japan has been cutting costs of production by managing raw material and finished good stocks based on the concept of ***'Just in Time'*** or JIT.

In the case of coal supplies to power sector in India, because both the coal production and rail transportation are government monopolies it is presumed that it would be difficult to apply the same principles. However, with a little extra effort, it may be possible to bring down coal inventories at various TPS by regulating the supplies. In any case, holding very large coal inventories resulting in use of deteriorated coal for power generation is a national loss.

4.4 Factors influencing optimal coal inventory

It is obvious that no general or adhoc norm can be imposed for optimal coal inventory at all power stations. Each utility operates under different conditions and has to determine its own optimal stocking policy and should be able to regulate supplies accordingly

The daily consumption of a utility cannot be the only criterion for determination of the optimal stocks. If that were the case, a very large utility with a daily consumption of 30,000 tonne will have to keep a stock of one million tonne perpetually, based on the existing norm, even if, for argument's sake, IR agrees to supply exactly 30,000 tonne daily without fail. Obviously, the optimal stocks depend on factors other than the daily consumption alone.

The coal consumption at a utility would depend on the size, its station heat-rate, specific coal consumption related to the quality of coal generally received at the utility and the plant load factor over a time horizon. This consumption in turn would only decide the quantity of daily supplies to sustain the desired generation.

The factors that should normally determine the optimum level of stock for the utilities are many and could be both endogenous as well as exogenous While some of these factors are under the control of the utility, others need policy intervention at the highest level. Some of the factors, which need to be considered for calculation of optimal stocks, are listed in the next few paragraphs.

4.4.1 *Location*

The location of a utility vis-à-vis the coal source has a large bearing on the optimal size of the coal stock The present norm has taken this into consideration on a very broad basis, ignoring the facts that even within a given slab, other factors such as transport logistics may become the deciding factor

A pithead utility close to a colliery with the capacity to supply coal in the long term should hold a very low inventory compared to a distant utility sourcing its coal from many coalfields / collieries. Even in such cases, if alternative sources are available, the inventory could be quickly restored in the event of supply dislocation from linked sources, preventing a stock out and hence a lower inventory can be maintained. Coastal utilities which are normally supplied domestic coal by rail may be supplied by coastal shipping in emergencies provided such a supply exists for some other utility in the vicinity. The reverse is also true i.e. if the utility normally gets supplies through the coastal route, coal can be supplied by all rail routes Similarly, a duel-fuel or multi-fuel utility using coal, oil and natural gas can sustain generation even if the supply of one of the fuels fails for a prolonged period. Obviously, the requirement for stocking should be lower in such cases.

4.4.2 *Transport logistics*

The mode of transport used to convey coal to the utility also has a significant impact on the size of inventory. A pithead utility with its own captive system of transporting coal may be allowed to keep the minimum stock depending on the reliability of the transport system. It is presumed here that both the production capacity and production plan of the supplying collieries are in consonance with the utility's demand. If the powerhouse, currently getting coal through its own transport system, is also designed for receiving coal by other modes (by road or rail) in an emergency, the system reliability will be better and stocks could be even lower.

The turnaround time of coal rakes, which among other factors depends on distance, will dictate the buffer stock and also the quantum of stock in transit. The turnaround time depends on the system of loading at the mine and unloading at the power station including delay at the exchange yard of the railways. It will also depend on the route the wagons normally take and whether it is congested. For the same distance of travel, the turnaround time may differ.

Past records of supply will influence the optimality of stocking. Disruptions could occur because of factors related to the source such as sub-optimal operation of the coal mine, its declining resources, propitiatory orders in the mine, and proneness to industrial unrest. Factors related to transport such as shortages of rolling stock, congestion en-route or at the ports, shortage of ships, shortage of trucks, derailments and accidents may also cause disruptions in supply The present level of diversion of coal rakes for operational reasons of the IR will also have to be accounted for in estimating the optimal stocks for a particular power station.

4.4 3 *Coal characteristics*

Characteristics of coal have a bearing on the coal stocks if deterioration in coal quality needs to be minimised if not eliminated altogether. All Indian coals are prone to varying degrees of self-heating or spontaneous combustion. Stocks need to be regulated depending on the time it takes for a particular coal to start self-heating If it is not possible to do so, the cost of maintaining the inventory would be very high since coal stacks would need constant compaction and water sprinkling to avoid coal fires which would increase costs

The maximum height to which the coal can be stacked without much maintenance and self-heating would restrict stock size. The process of self-heating is enhanced if the coal is stacked very high because the heat generated due to exothermic reactions does not get dissipated. The optimum height will vary from coal to coal and depends on intrinsic moisture, pyretic sulphur and also the rank of coal, in turn depending on the linkage of source.

4.4.4 *Stockyard*

The inadequate size of the stockyard of the utility can become the deciding factor for the size of stocks.[4] In cases where land is adequate and a larger inventory is stacked, coal has to be spread over a large area to reduce the stack height to prevent self-heating Spreading the stocks over a large area would increase the cost of rehandling and thus the cost of inventory holding

4.4.5 *The contribution of the utility*

Impact of the backing down/shutdown of one or more units of the power station on load demand would decide the level of risk that can be taken in maintaining a lower level of stock. The capacity of the grid to draw power from elsewhere in case of a shutdown/backing down would also impact the decision If a group of stations belongs to the same operator within a region (as is generally the case), the slack in generation of one could even be taken up by another permitting backing down/shutdown, even though it will come at a cost.

4.4.5.1 A practical model

However, in the given situation and data availability, a practical model to assess an optimal stock for a particular powerhouse could be developed on the basis of

(i) Capacity of the plant and average PLF
(ii) Extent of seasonal variation in generation, supplies and consumption
(iii) Coal requirement on daily, monthly and annual basis
(iv) Lead time for the wagons to arrive
(v) Frequency of daily arrival of rakes
(vi) Stockyard size

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[4] As in case of certain power plants in metro cities

(vii) Incubation period of coal
(viii) Maximum height to which the coal can be safely stocked
(ix) Acceptable level of rehandling

4.5 Present system of coal handling at Obra TPS

The coal handling system at Obra has developed in two phases. In the first phase a CHP for feeding coal to units 1 to 8 was put in place. The coal is received through the wagon tippler which is moved by a pair of belts (1A and 1B) to transfer point (TP1) or through ground bunkers (re-handled coal) to transfer point TP2 Belts 2A and 2B carry this coal to the TP3 from where belts 6A and 6B carry it to the crusher The crushed coal is fed to the coal hoppers of units 1 to 8 through the belt system (3AB and 4AB) and TP4.

In the second phase, CHP was built to feed coal to units 9 to 13 of 200 MW each by installation of a set of four wagon tipplers WT1 to WT4. Unloaded coal is taken to the crusher by a pair of belts 4A and 4B. The crushed coal moves to the coal hoppers of the units through the belt and transfer tower system consisting of 8A&B, TT1, 9A&B, 10,11 and 12A&B, and TT3. Re-handled coal is received at TT1 through belt 14 Interconnections between the two phases are available so that coal can be fed to units of both the phases by either of the CHP system Please refer to the line sketch of the layout of the coal handling system at Obra at annexure 4 1

4.6 Coal supplies

Though the coal supply to the Obra TPS is from NCL, CCL, and WCL, supplies from NCL and CCL are the dominant sources Between Jan 2001 and Jan 2003, WCL has supplied only 0 76 million tonne coal in the period May 2001 to Dec 2001 The following table 4.1 gives the past data on coal receipt at the Obra TPS

Table 4 1 Coal receipt at Obra

	2001		2002	
Source	Million tonne	%	Million tonne	%
NCL	2 89	64	3 07	56
CCL	0 89	20	2 45	44
WCL	0 76	17	0	
Total	4.54		5 52	

Obra TPS is not treated as a pithead plant because the delivery of coal is through the wagons of Indian Railways, though the TPS is situated very close to a major coalfield supplying about 60% of the total coal.

An examination of the past data of month-wise coal stocks shows that there are large fluctuations leading to situations of over stocking and also stock outs In the beginning of the financial year 2000-01, there was a serious shortage of coal at Obra resulting in stock-out for two consecutive months of April and May It is reported that pyrites or mill rejects were used during these months. In earlier months, Obra was having over one-lakh tonne stocks Following this stock-out, the stocks started getting built at a faster pace and year end closing stock reached almost three and a half lakh tonne. The stock is now being maintained at this level month after month.

The stocks at Obra TPS have varied between a low of zero tonne in the months of April and May 2001 and a high of 2, 56,715 tonne in the month of December 2001 which is much more than half a month's consumption. In April and May 2001, the plant had no stock at all while in the August, November and December 2001 the stocks crossed the 2 lakh tonne level In 2002 the stocks consistently remained above 2 lakh tonne and even crossed 3 lakh tonne level in the months of March, June, October, November and December

Table 4.2 Coal stocks at Obra tonne

	Stock level (tonne)	
Month	2000-01	2001-02
April	0	269066
May	0	290620
June	52083	330971
July	184169	284149
August	222491	259958
September	176773	292155
October	216311	361852
November	220615	304891
December	256715	333239
January	215620	346010
February	268628	345860
March	348221	270216

It is noticed that the fluctuations in stocks are either counter to the fluctuations in generation or follow the increase. Thus, the stocks increase with fall in generation and vice versa and in certain cases keep increasing with increasing generation. In either case, if this is allowed to continue, stock build up is bound to take place over a period of time, which is precisely what is happening here

Chart 4.4 Coal stocks and generation in 2001-02

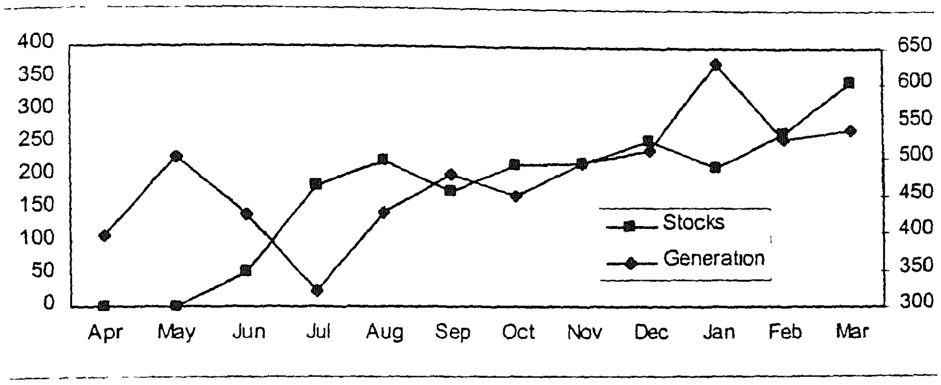
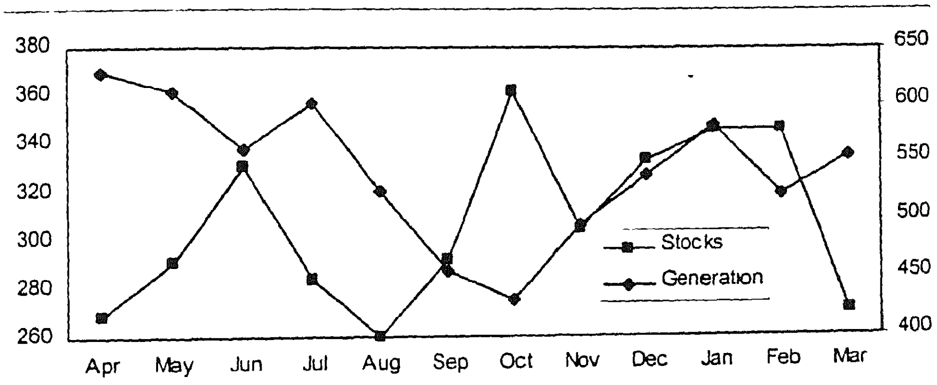


Chart 4.5 Coal stocks and generation in 2002-03



In the ideal situation, the receipt of coal at the TPS should match as closely as possible with the consumption of coal The marginal difference between the receipt and consumption, which cannot be avoided, would result in the small variance in the stocks, which would now vary within a close band of optimal stock

Table 4.3 Monthly coal receipt, consumption and stocks tonne

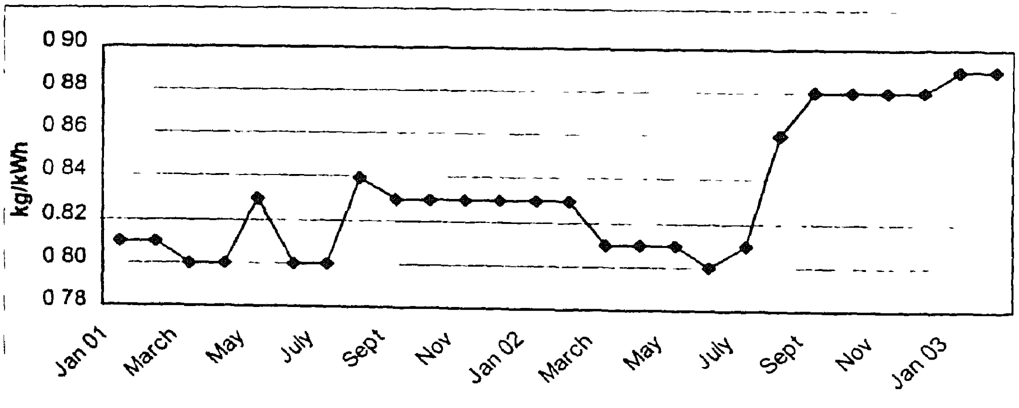
	Actual receipt	Consumption	Stock
Apr-01	217263	314974	0
May-01	376231	415455	0
Jun-01	373690	337679	52083
Jul-01	387915	255264	184169
Aug-01	394719	355128	222491
Sep-01	347257	395065	176773
Oct-01	413364	372832	216311
Nov-01	412817	408544	220615
Dec-01	456715	422376	256715

	Actual receipt	Consumption	Stock
Jan-02	483874	524581	215620
Feb-02	488578	434626	268628
Mar-02	515174	436162	348221
Total 01-02	**4867597**	**4672686**	
Apr-02	429464	508592	269066
May-02	515392	493286	290620
Jun-02	491998	451187	330971
Jul-02	440487	485656	284149
Aug-02	430244	452106	259958
Sep-02	435380	399439	292155
Oct-02	449933	379873	361852
Nov-02	383182	433150	304891
Dec-02	507342	476671	333239
Jan-03	533181		346010

4.7 An inventory model

Although the coal consumption depends on many factors including coal quality, it is directly related to the level of power generation. The specific coal consumption gives a direct measure of the coal consumption. Average specific coal consumption of last 2 years 2001 and 2002 was used for generating the coal demand forecast on monthly basis though the reported figure of coal factor of Obra is extremely high with high degree of fluctuations

Chart 4.6 Specific coal consumption for last three years



It may be noted here that using the past figures of specific coal consumption to estimate the future demand would obviously give an inflated figure.

Last year, supplies to Obra from NCL and CCL were in a ratio of 56% and 44% respectively The supplying collieries during the last year are listed below:

- NCL Dudhichua, Jayant (superior grades) Bina, and Jhingurda
- CCL DBB, Askoka, Khasmahal, KK, KD, Parej, Jarangdih and Tarmi

The major supplying collieries in NCL are Dudhichua and Bina located at distance of only 50-60 km, while that in CCL are Dakra-Bukbuka (DBB) and Karanpura-Dwarkhand (KD) in North Karanpura Coalfields at a distance of about 300 km. Thus, the lead time for almost 60% of the supplies from NCL are just a few hours while for the remaining 40% is about half a day. To achieve an assurance of 100%, one can safely assume a lead time of one day in this case.

Further, the analysis of the rake data for the Obra TPS reveals that on an average the plant received 3.8 rakes per day in 2001-02 and 4 3 rakes per day in 2002-03.

Chart 4.7 Average number of rake arrival (month-wise) at Obra TPS

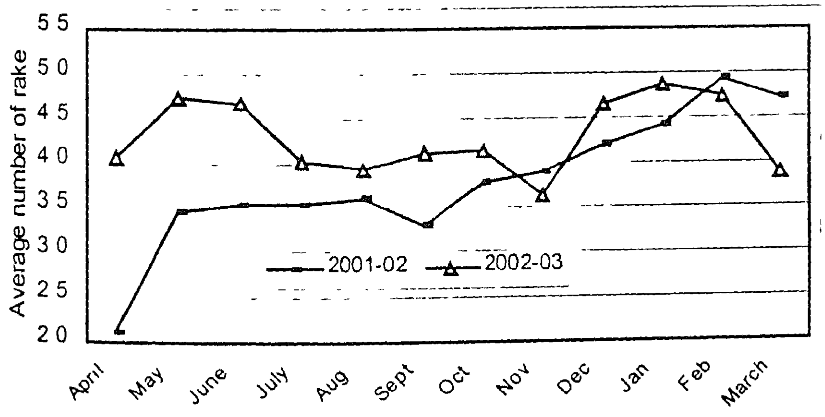


Table 4.4 Total and average number of rake arrival at Obra TPS

	Number of rakes 2000-01		Number of rakes 2001-02	
	Total	Average per day	Total	Average per day
April	63	2.1	122	4.1
May	107	3.5	147	4.7
June	106	3.5	140	4.7
July	110	3.5	125	4.0
August	112	3.6	122	3.9
September	99	3.3	123	4.1
October	117	3.8	128	4.1
November	117	3.9	109	3.6
December	130	4.2	144	4.6
January	137	4.4	151	4.9
February	138	4.9	133	4.8
March	146	4.7	120	3.9
Total	**1382**	**3.8**	**1564**	**4.3**

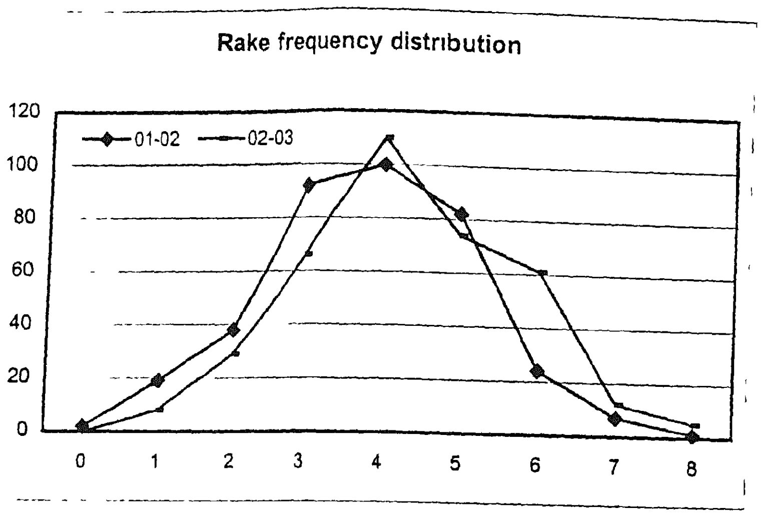
In the year 2001-02, coal rake did not arrived at Obra on only 2 occasions while in the next year i.e. in 2002-03, coal rakes did arrive on all the 365 days

Table 4.5 Frequency distribution of coal rake arrival

	Days (frequency)	
Number of rakes	2001-02	2002-03
0	2	0
1	19	8
2	38	29
3	92	66
4	100	110
5	82	74
6	24	61
7	7	12
8	1	5
Mean	3.8	4.3
Std Dev	1.4	1.4

Plotting the above data yields a normal distribution curve The mean of the above data is 3.8 and 4.3 for the respective years the value of standard deviation is 1.37 and 1.41 respectively

Chart 4.8 Frequency of coal rake arrival at Obra TPS



Since the very nature of demand is probabilistic, some unexpected variations can never be ruled out To take in to account monthly variations in coal consumption some level of safety stock has to be maintained. To take care of such monthly fluctuations (consumption exceeding the demand expectations) in coal demand, provision is made for safety stock. In order to give an assurance level that any particular deviation in demand can be met from the stock, the safety stock is given by·

Safety stock = k * s

Where 's' is the standard error in demand projection and 'k' is the assurance factor, which indicates the area under the coal demand distribution curve corresponding to the required assurance level In this model an assurance level of 99% has been taken.

Incorporating the consumption requirement of coal and the need to maintain excess stocks to meet monthly irregularities, the ordering quantity of coal is determined.

*Ordering quantity= Forecasted consumption + Lead time consumption + Safety stock (k * s)*

In the present scenario if the plant is expected to function at 52% PLF, the level of generation envisaged is 6551 MU and coal consumption is expected to be 5.43

million tonnes in the year 2003. After incorporating the irregularities on the demand and supply side it is estimated through the model that the efficient level of stock that the plant should maintain is 50,000 tonnes

The power plant has been operating at very low PLF The PLF in the year 2001 was about 43% while the PLF in 2002 was 52%. However assuming that the PLF would improve over the next few years and TPS would be able to operate at a PLF in accordance with the CEA norm of 68.5%, the coal consumption is expected to reach 7.15 million tonne at the current coal factor In such a event, the efficient level of stock that the plant should maintain is 77,000 tonnes

4.8 Coal stocking arrangements

Coal is very much like any other perishable commodity with a self-life of less than a month. It is recommended that it should be used on the basis of 'first in first out' concept to avoid any deterioration in quality This condition imposes the need for proper stocking so as to use the oldest stock first before the fresher stocks are consumed. Coal if stored for certain number of days, undergoes the process of spontaneous combustion. If coal is stocked for a longer period it starts burning and in the process loses its volatile matter and as a result the quality of coal stacked is greatly reduced. This deterioration in coal quality ultimately leads to higher coal consumption and higher coal factor

Generally, when the coal is retrieved from the yard, it is the coal available closet to the position of the reclaimer at that point of time The reclaimer is seldom moved to a position from where it can collect the oldest coal. Moreover, there is no possible way to know the age of the coal in the yard because the stocks are laid in a continuous stack along the reclaimer track. Heating is visible at many places There is a large degree of deterioration in coal quality associated with heating and fire in coal. This method of stacking generally facilitates in spread of fire in the entire stock Also large coal stocks result in an increase in the stockpile height above the recommended height of 2m which quickens the process of heating.

It is recommended that the stockpile should be broken into several smaller piles for convenience of controlling the fire and use of coal after quenching

4.9 Coal quality assessment

Sampling is the first step to quality determination of coal The object of taking a sample is to obtain a quantity of coal representative of the whole mass or lot of coal. The analysis of this sample will determine the overall quality of coal on which the final calculation for coal factor should depend.

It is easy to sample a homogeneous material, as any sample of any quantity taken from anywhere will represent the material in the larger lot. In case of a heterogeneous material like coal, it has to be proved scientifically and statistically that the sample drawn following a particular method is going to be reasonably representative. It also depends on the size of material sampled. If the heterogeneity extends to size also in addition to quality, then it still more difficult to get a representative sample unless the methods laid down are strictly adhered to. The method so laid down is based on sound principles. The fundamental requirement of sampling is that all parts of the material in the lot are equally accessible to the sampling instrument and particles have the same chance of getting included in the sample.

Over the years the process of coal sampling has been diluted to such an extent that the samples collected are no more representative of the material received. The third party samples are collected only from the top of a few wagons. The result of such a sample cannot be taken as the final quality of coal fed to the boiler It may be alright for commercial transactions (though TREI does not subscribe to it) but is definitely not right for coal factor calculations.

For specific coal consumption to be accurately calculated, it is very important to find out the CV of coal fed to the boiler on a daily basis. The sampling has to be from the vicinity of RC feeder for which necessary ports can be made and used Hourly samples collected for the day must be used to make one laboratory sample which should be analysed for ash, moisture and CV on daily basis.

4.10 Coal quantity assessment

There must be a method of knowing the exact quantity of coal fed to the boilers on a daily basis The best method is to have a well maintained gravimetric feeder on the mills Some of the plants rely on the belt weigher installed at strategic points. NTPC plants in close vicinity have gravimetric feeders. Some of their plants have belt weighers also.

In absence of both these arrangements, a rough estimate can be made if a proper record is kept of number of wagons fed direct to the coal bunkers or stacked on the ground The record of coal retrieved from the ground stock also needs to be kept. These records can yield the amount of coal fed to the boilers on any particular day. The details are given in the following paragraphs

The three shift reports are to be filled by the shift-in-charge and the data pertaining to his shift has to be summarized in the summary sheet

Format S1:	**Details of wagons unloaded**
Format S2:	**Details of wagons stacked**
Format S3:	**Details of coal quantity reclaimed**
Format S4:	**Summary**

Format S1: Details of wagons unloaded during shift

		Date				
Shift	Rake number	Supplying colliery	Number of wagons received	Arrival Time/Date	Release Time/Date	Number of wagons unloaded
From 21.00 to 00.00 Hrs						
From 00 00 to 05 00 Hrs						
Total number of wagons unloaded during the shift						

Format S2: Details of wagons stacked during shift

Time					
From	To	Stacked at (location in the yard)	Rake No.	Number of wagons	Quantity in tonne
From 21 00 Hrs to 00.00 Hrs					
From 00 00 Hrs to 05 00 Hrs					

Format S3. Details of coal quantity reclaimed during the shift

Time		Reclaimed from (location in the yard)	Reclaimed quantity tonne
From	To		
From 21 00 Hrs to 00 00 Hrs.			
From 00.00 Hrs to 05.00 Hrs			

Format S4: Summary

Total wagons unloaded	number	21 00 to 00 00 Hrs	
	number	00 00 to 05.00 Hrs	
Total quantity unloaded	tonne	21 00 to 00 00 Hrs	
	tonne	00 00 to 05 00 Hrs	
Total quantity stacked	tonne	21 00 to 00 00 Hrs	
	tonne	00.00 to 05 00 Hrs	
Total quantity reclaimed	tonne	21 00 to 00 00 Hrs	
	tonne	00 00 to 05 00 Hrs	

The summary sheets of all the three shifts (Format S4) have to get compiled in the general shift in the morning in the Format D5 The position is compiled for 00 hours, hence the break up of the night shift. As is clear, once we have the various quantities in tonne for the day, coal consumption for the day can be easily calculated by

Daily coal consumption = (Quantity of coal unloaded + Quantity of coal reclaimed - Quantity of coal stacked)

Format D5 Daily coal consumption details tonne

Date					
	00 to 05	05 to 13	13 to 21	21 to 00	Total
Total quantity unloaded					
Total coal quantity stacked					
Total Coal Quantity Reclaimed					
Daily Coal Consumption					
Quantity of coal unloaded					
Plus Quantity of coal reclaimed					
Minus Quantity of coal stacked					
Daily coal consumption in tonne					

The daily coal consumed can be made more accurate if the bunker difference is accounted for in the beginning and at the end of the day. This, however, does not make a large difference because it cancels out during the month.

Once the above system has been fully established in the coal control, the monthly report can be made more accurate by accounting for various losses

Since the wagons are weighed either at the colliery end or at the power house end, all extraneous material is also included in the weight of coal Large parts of these are invariably removed in two stages before the coal is pulverised. The first one is at the stage where large stones are hand picked and removed. These are measured periodically for getting compensation from CIL.

The second one is the rejects thrown out by the mills. The rejects are also removed for which measurements are available The total of stone picking and mill rejects can be deducted from the final figures of the monthly report as given below in Format M6 to yield a more accurate monthly figure of coal handled and consumed.

Format M6. Accounting for losses (at the end of the month)

Total Reject removed from mills	*(minus)*
Total Stone removed (picking)	*(minus)*
Actual coal consumption in tonne	

If the opening coal stock is measured accurately by surveying, the coal inventory can be monitored more accurately thereafter because the above system would also yield the coal sent to stocks The physical measurements should then tally with the monthly sheet data.

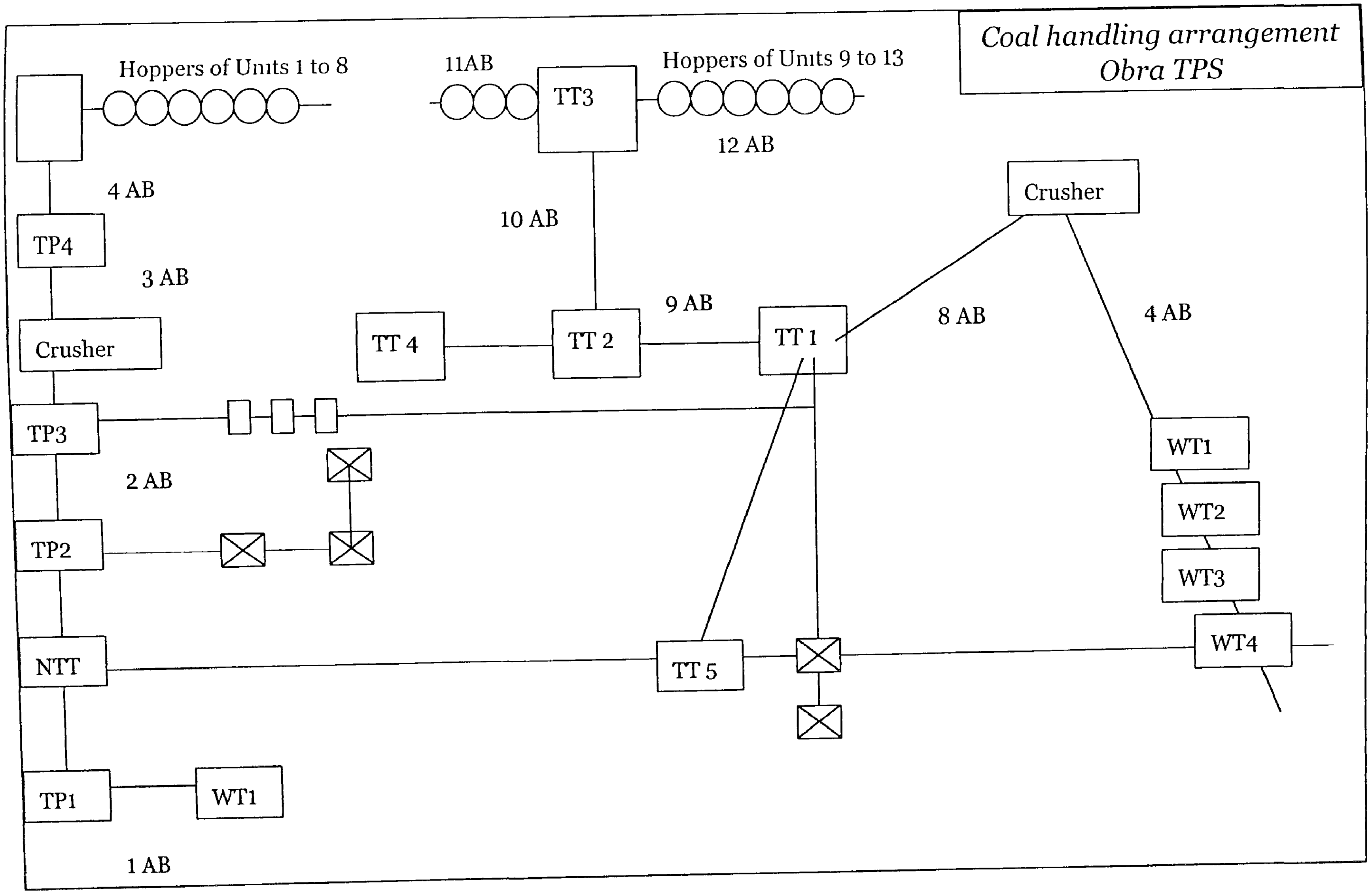
4.11 Finally

Presently there is no way to find out the quality and quantity of coal fed to the boilers at Obra on a daily basis The sampling procedures are faulty and can never give representative results for the quality of coal. The volumetric feeders appear to be inaccurate. The system of reporting coal receipt, stacking and feeding to the boiler is deficient to the extent that the quantity of coal actually fed to the boiler cannot be assessed with reasonable accuracy. It seems the consumption of coal is reported based on the units generated and assumed station heat rate.

As mentioned earlier, the reported figure of specific coal consumption is very high and leaking of coal from the stocks may be a contributory factor

A reasonably accurate knowledge of quality and quantity of coal received, consumed and stocked would yield a reasonably accurate coal factor which would also be important for assessment of commercial implication of fuel cost.

Coal handling arrangement
Obra TPS



5 Recommendations

5.1 Performance analysis

A summary of major observations and recommendations that emerged during the performance analysis of boilers is given below:

5.1.1 *Anpara Thermal Power Station unit#3 of 210 MW*

- Boiler was found to be operating at 75 32% efficiency against the design of 85%
- The boiler was operating at 190±5 MW load, with deficiency of air and at higher flue gas temperature. Cold air ingress was also observed at air preheater.
- It is recommended to operate boiler at 25% excess air and 140°C flue gas temperature. Because of this, boiler efficiency is likely to improve to 80.68%.
- The savings of coal in this regard would be about 68995 tons per annum or Rs. 620.9 lakh based on the coal price of Rs. 900 per ton.

5.1.2 *Obra Thermal Power Station unit#12 of 200 MW*

- Boiler was found to be operating at 79 77% efficiency against the design of 86.15%
- The boiler was operating at 180±5 MW load, with high excess air and at higher flue gas temperature. Cold air ingress was also observed at air preheater.
- It is recommended to operate boiler at 25% excess air and 140°C flue gas temperature. Because of this, boiler efficiency is likely to improve to 83.92%.
- The savings of coal in this regard would be about 38388 tons per annum or Rs. 441.4 lakh based on the coal price of Rs 1150 per ton.

5.2 Possibilities for improvement

By improvement in the boiler efficiency of the boilers of unit unit#3 (Anpara), savings in specific fuel consumption and in are mentioned in table 5 1 below.

Using the observed boiler efficiency and the calorific value o evaluation, it is possible to calculate the specific coal consum designed heat rate of turbine generator. This is just for comp understand the deviation between design and actual conditic

Specific coal consumption = Turbine Generator heat rate / Boiler efficiency x CV of coal

For a 210 MW units the heat rate is taken as 2130 kCal/kWh units it is 2012 kCal/kWh as provided by the respective plan

Table 5.1 Comparison of specific coal consumption

	Present boiler efficiency %	Improved boiler efficiency %	Savings Rs lakhs/year	Sp fuel cons as per TPS record kg/kwh
Anpara 210 MW	75 32	80 68	620 9	0 766
Obra 200 MW	79 77	83 92	441 4	0.815

** Cost of coal has been taken as Rs 1150/tonne for Obra and Rs 900/tonne for A

- Coal loss factor has not been considered in the above c
- It is clear from the above table that the reported specif is much higher compared to the actual measured duri
- The specific coal consumption would fall further if the for preventing heat losses is accepted and implemente parameters constant which have bearing on specific fu The savings through this could be Rs 621 lakhs/year fc Rs 441 lakhs/year for Obra
- Boiler efficiency of Obra is higher compared to that of

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[5] The specific coal consumption as observed during test has been obt environment and on that day The figure for the whole year would

- Calorific value of coal used during testing at Obra was found to be 4865 kCal/kg (as fired basis) whereas the design coal is 4750 kCal/kg. The corresponding values for Anpara are 4071 kCal/kg during the tests as compared to the design value of 3750 kCal/kg.

5.3 Coal inventory management at Obra TPS

1. Operation of stage II CHP at maximum capacity
   Since the phase II has high capacity belt system compared to the earlier system, loading of coal bunker should be as fast as possible. This would spare time for cleaning, maintenance etc in addition to saving in auxiliary consumption.

2. Accurate assessment and reporting
   a. In the interim, method of reporting from the coal yard has to be modified to collect and report data on receipt, stacking, retrieval and feeding to the boilers on shift and daily basis. This would generate a reasonably accurate data on coal consumption, which should be cross-checked with actual measurement of monthly stocks at the ground.
   b. A regular collection of coal samples just before it reaches the mills must be done in every shift to make one sample for the day. This must be analysed for ash, moisture and GCV on daily basis
   c. Restrict indiscriminate stacking; stacking to be gradually reduced from the current level to reduce rehandling costs
   d. All coal stacks must be of regular shape, preferably trapezoidal or conical to facilitate accurate measurement
   e. Bulk densities of Indian coal, both for normal and compressed stocks must be determined regularly to arrive at an average figure for future use
   f. Direct feeding of coal to bunker as far as possible to avoid unnecessary stacking/reclaiming of coal

3. Stacking of coal
   a Large spread of coal stocks on both sides of the S/R is highly wasteful
   b. All coal stacks should be kept compressed by using dozer to remove air pockets so that fire can be prevented

- c. Stacking frequency should be minimized Frequent stacking results in a number of problems including large spread of coal all over the stockyard.
- d. Coal stacks must be used on 'first come first out' basis. Older stacks must be fed to the bunker at the first opportunity and should never be allowed to be on the ground for more than 20-25 days to avoid deterioration in coal quality resulting in lowering of the TPS performance
- e. For optimisation of coal stocks to materialise in the present situation, the utility or the electricity board must enter into a legally enforceable fuel supply agreement with CIL. The agreement must contain a clause pertaining to the timeliness of supplies with bonus and penalty clauses if need be No 'best effort' contract can serve any purpose as is clear from the existing situation. Similarly, there must be a back-to-back contract with the IR for supplying sufficient number of empty wagons to the colliery and loaded wagons to the thermal power station at a mutually agreed frequency. Such agreements were reached with a couple of independent power producers in the past[6] though ultimately these power plants did not materialise.
- f. There is a need to strengthen the security measures to prevent pilferage of coal

4 Advantages

Apart from providing full control over coal consumption for the plant as a whole, the system is expected to provide the following quantifiable advantages.

1. Keeping an optimum coal inventory at the plant would mean
   - a. Less deterioration in coal quality due to self-heating and aging resulting in better quality of coal fed to the boiler. This would, in turn result in better coal factor and efficiency
   - b. Lower re-handling means lower demand on dozer, resulting in lower diesel consumption and lower costs
   - c. No fire would mean no water use for fire fighting
   - d. Lower auxiliary consumption due to reduced re-handling
   - e. Lower overtime expenditure in managing coal stocks

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[6] In cases of Hinduja and Bina Power

2 Savings in implementing the recommendations would be
  - a Savings in interest on the working capital in holding optimal stocks (between 50,000 and 77,000 tonne) compared to highly fluctuating stocks ranging from nil to more than three lakh tonne
  - b. Diesel consumption in dozer would reduce to a large extent
  - c Overtime would be reduced to a great extent
  - d. The other savings such as less use of water, preventing deterioration of coal quality
  - e. Cost of re-handling would be reduced

Annexure A

Comments from UPERC and response of TERI on the Draft Report on Boiler Efficiency and Coal Inventory Management Obra and Anpara

1. *The problem of incapability of handling excess air by ID fan is not understood when excess air level in the boiler is much below the desired causing high quantity of CO (>1%).*

The incapability of ID fans of unit# 3 of Anpara could be due to problem in impellers and that is why they are not able to generate the required suction. Another probable cause is the large leakages in the rotary air heaters and because of this, ID fans have to cater additional quantity of air, which is ingressed from a point near to ID fans Due to this short-circuiting, desirable suction is not available to meet the requirement of optimum excess air quantity in the furnace. However, a detailed study needs to be carried out to ascertain the causes which have also been suggested by BHEL who are the supplier of unit#3 boiler

2. *On page 20, it is indicated that power plant is using better coal that the coal for which the boiler is designed When carbon content and GCV are high whereas the ash content is lower that the design value, whether boiler was able to achieve MCR. If yes then what are the factors limiting maximum generation to 180+ 5MW.*

The plant officials at Obra had the impression that quality of coal feed is generally inferior to the coal for which this boiler is designed and due to this the mills are not able to meet the desired coal quantity to run boiler at full load However, the composition of the coal was found to be better than the design one (report attached as annexure-2.1). Now in retrospect, it is felt that the problem lies with the mills, which is not able to supply the required quantity of pulverized coal to run boiler at load higher than 180±5 MW Mismatch between the capacities of ID and FD fans was also observed for this boiler, as they were not found to be interlocked Due to this, occasional furnace pressurisations were observed at the load of 180±5 MW and ID fans are not able to support load above this.

3. *The report shows improvement in efficiency due to optimization of excess air level and flue gas temperature Improvement due to other factors like loss due to hydrogen and moisture in coal, loss due to unburnt in ash need to be analyzed in terms of cost- benefit analysis*

Reduction in losses due hydrogen and moisture in coal, due to moisture in air, etc, because of optimization of excess air and flue gas temperature have also been incorporated in the table-1.3.2 2c and table 2.3 2 2b. (Incorporated in the report)

However, reduction in unburnt loss due to increased fineness of coal by improvement of health of the coal mill cannot be calculated directly For knowing this, unburnt content in ash at improved situation has to be tested in laboratory and then only the improvement in efficiency can be calculated.

4. *A study was carried out by expert group constituted by CERC in Year 2000, to review the norms of operation of TPS based on operational data and performance of CGS along with the feedback of other stations and based on information already in CEA. The expert committee when considering the heat losses in the boiler operation includes Air Pre-heater leakage, loss due to coal nozzle erosion and handling loss of coal and mill rejects. These have not been included in the list of heat loss items of boiler of Obra and Anpara stations.*

The efficiencies of boilers are calculated considering the leakage in air-preheaters Air infiltration in air-preheaters reduces the flue gas temperature and, therefore, the new temperatures are calculated adjusting the leakage. Loss due to leakage in air-preheaters is incorporated in the loss due to dry flue gas. The boiler's system boundary consists of boiler, economiser and air-preheater and, therefore, losses in the mills need not be considered in the boiler efficiency

5. *What is the actual coal size observed through 200-mesh sieve?*

Sieve analysis of coal is attached as annexure-2.4 and 3 4 in the report.

6. *Chart shown for coal stock and generation in 2001-02 and 2002-03 are identically same?*

There was a mistake in pasting of the graphs It has now been corrected

7. *On page 47, the deficiencies in procedure of coal quality assessment and recommended methods needs to be elaborated more.*

The elaborated procedure for quality and quantity assessment has been added in the final report

Annexure B

Comments from UPRVUNL and response of TERI on the Draft Report on Boiler Efficiency and Coal Inventory Management Obra and Anpara

Tests for determination of efficiency of boiler were carried out by TERI on 200 MW boiler of U#12 of Obra and 210 MW boiler of U#3 of Anpara in April 2003. Weather was dry having DBT and WBT respectively at Obra and Anpara as 30°C(27°C) and 30°C (25.3°C) Following important points regarding captioned subject need special mention:

1. *U#12 of Obra was commissioned on 28.3.81 and has lived a life of more than 22 years*
2. *U#3 of Anpara was commissioned on 12 3.88 and has lived a life of more than 15 years.*
3. *With the passage of time, efficiency of turbine and generator also deteriorates, which has not been given any cognizance. TERI has taken turbine heat rate of a new turbine for calculation of coal figure, taking generator efficiency equal to 100%.*
4. *In almost all the cases, even when a new thermal set is commissioned, during performance guarantee test we are not able to achieve designed operating parameters due to various seasons.*
5. *In foreign countries we can afford to have replacement of new spares before their working envisaged life is over. But unfortunately in India we generally resort to repair technology to a greater extent due to paucity of funds and non availability of shut down of unit due to power demand being more than generation almost round the year. We do not have additional generation capacity We do not have basically ground, middle and peaking load stations.*
6. *Besides above in most of the cases time for maintenance of spare auxiliary is not available due to inferior and bad quality of coal. This results in higher auxiliary consumption and longer shut down for repair. It does not become possible to attain original expected efficiency and life*

The STG heat rate does not deteriorate much with the time if all the LP/HP heaters are in operation and boiler water quality is maintained Thus for this study, it was reasonable to assume that STG heat rate is the design heat rate. However, a detailed study for STG heat rate should be carried out to get the actual figure. This was not in the scope of this study.

Taking specific points

A. Obra Unit no. 12 of 200 MW

The TERI has theoretically calculated the specific coal consumption on the following formula

$$\text{Specific coal consumption} = \frac{\text{Turbine Generator Heat Rate}}{\text{Boiler Efficiency} \times \text{CV of coal}}$$

TERI has considered Heat Rate as 1985 K Cal/Kwh, Boiler Efficiency 79.19% and CV of coal as 4917 K Cal/Kg for 200 MW units in above formula, therefore, specific coal consumption comes out to be 0 510.

The above calculation does not appear to be correct in view of the following observations

1. *The design heat rate for 200 MW unit is 2012 K.Cal/Kwh at boiler efficiency of 86 15% and at full load. The TERI has mentioned the boiler efficiency as 79.19% at 180 ±5 MW load in its report but has not derived the actual heat rate as per test conducted by them.*

The design heat rate for the TG set was not provided by the plant; so it was taken as 1985 kCal/kWh as available from literature. Now the heat rate suggested is 2012 kCal/kWh, the calculation of specific fuel consumption can thus be revised to 0.517 kg/kWh instead of the value of 0.51.

It may also be noted that the heat rate of TG set generally remains constant in the range of 80 to 100% load It is affected only if the unit is operated for a long time at lower loads Thus, there will be no difference in heat rate at 185 MW or 200 MW output from the TG set

2. *Since TERI had asked only to feed a specific quality of coal in the unit under test, therefore, the coal sample taken by them is not the representative sample for the whole year as OTPS is receiving coal from different coal mines of different coal companies and of different schedule grade varying from "C" to "F", some time even ungraded. However, the average CV during the year 2002-2003 is 3617 K.Cal/Kg. as per record of Express Laboratory.*

TERI had asked for supply of uniform grade of coal (from only one source/rake) so that the grade of coal fed to the boilers during testing could be determined. Had it been varying, it would have been impossible to conduct the tests.

We agree that supplies come from many sources and are of many grades. However, since the current sampling procedure cannot yield representative results, it is difficult to agree to the results of the Express Lab which should be used only for commercial purposes.

Since the unit is quite old and designed heat rate is 2012 K.Cal/Kwh at 200 MW load, therefore, for practical purposes the heat rate may be taken as 2300 K.Cal/Kwh as for Anpara 210 MW units, heat rate is approximately 2300 K.Cal/Kwh Thus specific coal consumption, with heat rate as 2300 K.Cal/Kwh, boiler efficiency of 79.19% and GCV of coal as 3617 K.Cal/Kg works out to be as under.-

Specific Coal Consumption

$$= \frac{\text{Heat Rate}}{\text{Boiler Efficiency x GCV of coal}}$$

$$= \frac{2300}{79.19 \times 3617}$$

$$= 0\ 80 \text{ Kg/Kwh}$$

Which varies in permissible limits with the reported coal consumption on assessment basis i.e. 0.815.

The rationale of considering the present heat rate at 2300 kcal/kwh against the design value of 2012 kcal/kwh is not understood Such arbitrary values would obviously lead to erroneous results and conclusions

3. *TERI has conducted the test on one selected unit for a duration of eight hours whereas it should have been carried out on other old units also i e. unit no 9, 10, 11 for assessing the actual health of 200 MW units. Therefore, the findings of this test cannot be generalized for other units of 200 MW*

The thermal efficiency test of a boiler as per standard ASME PTC4 is applicable for the operating conditions (fuel, ambient, steam turbine and generator) applicable that very day. The purpose of study was to evaluate this instantaneous thermal efficiency of the boilers and calculate the specific coal consumption (kg/kWh), on the basis of boiler efficiency, on that day, with the assumption that the steam turbine generator (STG) is operating at design conditions It may be noted that the sp. fuel consumption calculated this way does not represent the average of a month or a year for the unit. For yearly average, similar tests have to be carried out every fortnight for every unit and then average the results for the year to get a representative average for the station.

B. Anpara Unit no. 3 of 210 MW:

1. During testing of boiler, both the test equipments brought by M/s. TERI team were non-functional. The instruments were giving erratic reading, however, the readings taken by them at eco inlet, AH inlet & AH outlets were reported as follows -

ECO INLET	*AH (INLET)*	*AH (OUTLET)*
(L) O_2-0.4 -0.6%	*2%*	*8% approx.*
(R) O_2 0.2%	*1.6%*	*9% approx*

The O_2 readings of AH inlet is shown correctly in the comments but O_2 readings of AH outlet has been wrongly quoted The actual measured values for O_2 at AH outlet-left and right were varying in the range of 9-11% and 11 5-12.5% respectively The average of this is 11%, which is taken for calculations

As both their equipments were not functioning properly and M/s. TERI has shown the excess average of O_2 contents in flue gas after air heater as 11% instead of 8%-9% as measured at site In table no. 1.3. 2 2A, the excess air level has been shown 110% after air heater as per their own assumption.

The problem in the instruments used by TERI was due to the improper suction of the sample. The instruments were fully functional but because of improper suction (such as, in a gas pocket, near corner or a point where soot deposition is high, etc) at few sample points, the readings were found to be unacceptable Similar problem is also faced by flue gas analyser instrument of power plant This is the common problem with such sophisticated electronic instruments due to unfavourable conditions If the sampling is not proper then it may suck atmospheric air and lead to the wrong reading. Locations of sample ports and isolation of it from the atmospheric air is, therefore, of immense importance while taking the readings. However, same instrument functioned adequately with proper sampling points later.

2. Due to considering 11% O_2 after AH M/s TERI has evaluated 122°C temp as 218°C which is not correct Actually this temp is always found in the range of 140° C +5°C and due to such assumption it has resulted in heavy drop in boiler efficiency.

The measured flue gas temperature, after air heater was 122°C with excessive cold air ingress, which is taking place in air heaters from FD side to ID side Ingressed cold air also absorbs heat from flue gas resulting into the lower flue gas temperature, and thus reduced heat recovery in air heater. Had there been no air ingress, the flue gas temperature would have been 218°C. Therefore, this calculated flue gas temperature has to be considered for calculating the boiler's efficiency Though, cold air ingress is common in rotary air heater but it is also a fact that the heat transferred to combustion air is reduced because of this and, hence, the boiler efficiency is affected. To reduce this, the seals between the hot and cold points within the air heater must be changed in every annual overhaul of the boiler.

3 The load on machine was kept 195 + MW to keep the machine in stable condition due to grid disturbance otherwise machine could have been run on full load.

It may also be noted that the heat rate of TG set generally remains constant in the range of 80 to 100% load. It is affected only if the unit is operated for a long time at lower loads Thus, there will be no difference in heat rate at 185 MW or 200 MW output from the TG set.

4. As per our calculation, the boiler efficiency of unit no. 3 is around 80%

5. Unit no 3 has already run approx 10 months after annual overhauling on which test was performed. As such there are chances of air ingress from atmosphere through expansion bellows etc. of air pre heater and mixing of primary/secondary air flue gas is obvious.

6. Specific coal consumption has been calculated theoretically on the following formula

$$\text{SP COAL CONSUMPTION} = \frac{\text{TURBINE GENERATOR HEAT RATE}}{\text{BOILER EFFICIENCY X CV OF COAL}}$$

M/s TERI has used above formula for unit no.3 to calculate sp. coal consumption with heat rate assumed as 1970 K Cal/Kwh, the boiler efficiency 75 4% and calorific value of coal 4071 K.Cal/Kg and specific coal consumption has been calculated 0.642 Kg./Kwh.

Whereas turbine heat rate of 210 MW unit no.1 during the P.G. test was 2130 K Cal/Kwh as is evident from the power plant operation volume-II (copy enclosed as annex 1) against the design value of 1985.3 K.Cal/Kwh. On 2130 K Cal/Kwh the turbine heat rate, the specific coal consumption was worked out 0.72 Kg /Kwh

The design heat rate for the TG set was not provided by the plant; so it was taken as 1970 kCal/kWh as available from literature. Now that the heat rate suggested is 2130 kCal/kWh, the calculation of specific fuel consumption can thus be revised to 0 694 instead of 0 642 as given in draft report.

The above calculation does not seem to be correct due to the following

a) *The design heat rate for 210 MW (Unit No.3) is 2470 K.Cal/Kwh, at boiler efficiency of 85% at full load M/s TERI has mentioned that the turbine heat rate on actual was found to be 3200 ±50K Cal/Kwh at boiler efficiency of 75.4% while load on machine was 190 ± 5 MW*

b) *The coal sample taken by M/s. TERI for testing and determination of calorific value of coal, cannot be deciding factor for quality of coal for the whole year. As we are getting the coal from 4 different mines having different grades of coal ranging from grade-D to F and some times supply of ungraded coal also*

In view of above facts, the specific coal consumption for 210 MW units taking 2300 KCal/Kwh turbine heat rate, 80% Boiler efficiency and gross calorific value of coal as 3750 KCal/Kg (average calorific value of coal during year 2002-2003 as per DAS record) will be as follows -

$$\text{SP.COAL CONSUMPTION} = \frac{2300}{80\% \times 3750} \text{ Kg/Kwh}$$

$$= -0.766 \text{ Kg/Kwh}$$

Thus the specific coal consumption as per TPS record is reasonable.

C. Coal Inventory Management at Obra TPS.

Most of the suggestions given by TERI are known to power station O&M personnel and as far as feasible guidelines are being adhered to

The basic aim of examining and suggesting an improved coal inventory management system is to bring coal as a fuel in to sharper focus. With the power sector reforms, it is now imperative that fuel costs get monitored more closely

Normally the major thrust of a particular sector lies on its final product or service. For example, for CIL it is 'millions of tonne of coal produced' irrespective of its quality, timeliness etc For Indian Railways it is 'million tonne kilometer' for freight and 'million passenger kilometer' for passengers irrespective of whether the toilets are clean or AC is functioning Similarly, power sector monitors 'millions of unit generated' Coal or fly ash is, if at all, a concern of secondary importance

We believe that 'something which is not measured can not be controlled' We feel that knowing the exact grade of coal as fired to the boilers (it would be always different from the present grade determination for commercial transactions with CIL) and measuring the quantity of coal fed to the boiler on a daily basis would help in pinpointing the problems of high fuel cost, which then can be controlled.

But some points are not feasible and in the overall interest of UPRVUNL, and are enumerated in short as under.

1 *Subsidiaries of CIL, the monopolised coal suppliers do not normally adhere to the linked coal quantities and constant perusal is essential at our level. The position further aggravates when Indian Railways, the sole transporters of coal also do not follow the requirement of placement of empties at the disposal of coal supplying companies. In short we can say that we do not have proper control on coal suppliers and transporters due to obvious reasons*

We do not agree to the contention that nothing can be done to improve the situation as both Coal India and Indian Railways are government monopolies Unless various power boards start putting pressure, there is no hope for improvement. The subject of optimality of coal inventory is already being discussed at various forums and we are sure that with active support from the power boards, coal inventories can be optimized at the power plants.

2 *Quality of coal supplied seldom meets our requirement of proper grade and volatile matter to have better combustion and reduce coal and oil consumption.*

We fully agree to this contention that coal is supplied from many sources and vary from grade D to grade F, as mentioned elsewhere. However, the present system of collection of coal samples, as pointed out in the report, can never yield results which can be called representative of the whole rake. Since the exact grade of coal is not determined at the power plant, it is difficult to agree that quality of coal supplies seldom meets the requirement and volatiles are always low. Unless arrangement for proper sampling (from running belt) and accurate analysis is established and used by the power plant, it is difficult to agree to the above statement. It is important that coal samples are collected daily from a point close to the RC feeder to determine the quality of coal on 'as fired' basis

If low volatile coal is being supplied on a regular basis then the power plant is definitely getting 'very old stock coal' from CIL which has suffered heating thereby losing volatile matter. This calls for a closer supervision by the TPS on the loading point so that only fresh production is dispatched.

Since power plants hold large coal inventories, stocks are always undergoing heating and are most of the time on fire, the volatiles are bound to escape. If stocks are optimized and 'first in first out' principle is strictly adhered to in feeding coal to the bunkers, this loss can be completely eliminated.

3 *Stones, shales and other foreign material received with coal, increase unloading time of rake, handling difficulties and increase wear and tear of handling plant At sizeable occasions breakdowns occur All these result in escalation in coal cost delivered at boiler besides increasing cost of maintenance*

We fully agree that coal supplies do contain many extraneous materials but as we mentioned earlier, enhancing supervision at the loading point and constantly raising these issues at various forums can improve the situation. Accepting it as our fate would not help

4 *Seasonal effects on the supply of coal mainly in rainy season and labour problems both at suppliers establishment and at power station may cause interruption in coal delivery and in turn hindrance in power generation.*

Optimized supplies should be linked to the program of power generation If there is a dip in generation during monsoon, coal arrival should be accordingly adjusted. With increased generation coal arrival should also increase. If this happens then theoretically there is no need to keep any stock at all. As this does not happen in practice, stocks are maintained for such eventualities as labour problems or accidents etc. These factors have been taken into consideration in the model while optimizing the stocks.

The optimal supply of coal would vary form plant to plant. It is unique for every plant and would depend on the program of generation and maintenance for the year but the linkage committee (short term) has decided a percentage for each quarter and allocates coal based on these percentages Whether a particular plant is running all the units or taking some of them for AOH during the said quarter is not at all considered. This results in excess supplies resulting in huge inventories at the TPS.

5 *If a unit of 200 MW is stopped for one day, it shall cause a loss to the Nigam to the tune of 65 lac at a PLF of 85% and supply rate of Rs 1.60/unit*

Though CIL and IR are monopolies, they are also responsible towards the supply of coal to thermal power stations. No power plant has ever been allowed to stop for want of coal. Even backing down of the units due to shortage of coal has not come to our notice.

The shortages reported by TPS are generally due to problems arising out of the commercial transactions between the TPS and the coal sector or the railways

It is easy to calculate the extra cost of working capital involved in keeping large inventories but is very difficult to calculate the loss due to the following reasons but would be very large for a large power plant

- Feeding of deteriorated coal with low volatile and high ash
- Extra rehandling of coal stocks
- Fire fighting including the cost of water

6 *In view of foregoing it appears quite impracticable and unprudential, though on the face of it theoretically it may look convincing and encouraging to have a stock of 50,000 to 77,000 tonne It is still felt necessary to accept the guidelines of CEA in this regard, that is to have a stock of 15 days at pit head power station while a stock of 30 days may be maintained at power stations away from pit head*

We would like to stress the fact that the optimized stock level of 50K to 77K is not theoretical but it looks like a very small quantity since our minds are conditioned to have very large stocks Moreover, since the various losses due to holding very large inventories of coal except the cost of working capital involved can not be easily quantified, we tend to rubbish the idea. Also, the fuel cost is a pass through to the consumer and therefore is not a priority of the power producer However, reducing the fuel cost in a coal fired TPS would result in substantial reduction in final cost of power generation

As pointed out in our report, the CEA norms were ad hoc to start with and have remained so even after the revision The norms should be based on sound scientific basis

It is quite enlightening to read the objections put forth by CIL and IR when the power sector was requesting for lowering of the norms. It is clear form the report that CIL and IR do not want any reduction in the coal inventory of the power stations for obvious reasons

While Japan is cutting costs by maintaining inventories on "Just-In-Time" concept, we are sticking to an adhoc norm which in any case is highly wasteful

Under the circumstances it will be worthwhile if TERI discusses the matter with UPRVUNL before finalization of their recommendations